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SYNTHETIC PETROLEUM FOR DEPARTMENT OF DEFENSE USE

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Stanford Research Institute

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This final report was submitted by Stanford Research Institute under Contract F30602-74-C-0265. This study was conducted in the Operations Evaluation Department, Robert M. Rodden, Director, of the Engineering Systems Division; and in the Center for Energy Studies, J. Patrick Henry, Director, of the Economics Division. The project leader was Richard L. Goen. The work on coal liquefaction was performed by Carroll F. Clark, and the work on refining the synthetic petroleum by Michael A. Moore.

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The study assesses the feasibility of meeting part of the DoD energy requirements by synthetic petroleum (syncrude) from coal. The DoD petroleum requirements are summarized. The various syncrude processes are described, and the technical and economic aspects of converting a typical eastern coal and a typical western coal to refinery grade syncrude are analyzed. Refining of this syncrude is analyzed for several cases involving either new plants or modifications to existing refineries, and alternative product slates. Plant location considerations, schedules, and constraints are also covered.

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PREFACE

This study was conducted in the Operations Evaluation Department, Robert M. Rodden, Director, of the Engineering Systems Division; and in the Center for Energy Studies, J. Patrick Henry, Director, of the Economics Division. The project leader was Richard L. Goen. The work on coal liquefaction was performed by Carroll F. Clark, and the work on refining the synthetic petroleum by Michael A. Moore.

The study was conducted for ARPA under the cognizance of Rudolph A. Black. The Air Force Project Engineer for the study was James R. McCoy of the Air Force Aero Propulsion Laboratory at Wright-Patterson Air Force Base, Ohio.

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I INTRODUCTION AND SUMMARY

Background

The energy shortage has been developing over the past several years as energy demands increased faster than energy supplies. This problem was brought sharply into focus by the recent Arab oil embargo.

Petroleum supplies are of particular concern to the Department of Defense (DoD) since petroleum products are the principal DoD energy source, with jet aircraft and other vehicles the major users. Although DoD accounts for most of the federal petroleum consumption, DoD use is still only three percent of U.S. petroleum consumption. However, an alternate and secure source of supply would be desirable to avoid diversion of fuels from the civilian sector.

Production of petroleum in the United States reached a peak in 1970 and now provides only about two-thirds of U.S. consumption. Although higher prices may stimulate domestic production, there are doubts that a substantial increase in domestic production can be achieved because of the decline in remaining petroleum resources.

Coal resources, however, are many times larger than petroleum resources. The production of synthetic petroleum (syncrude) from coal would provide a vast resource base for petroleum supplies and reduce vulnerability to actions of the petroleum exporting countries.

Although production of synthetic petroleum from coal is technically feasible, until recently the costs were not competitive with the former low cost of crude oil. The sharp increases in petroleum prices over the past year have greatly improved the economic competitiveness of syncrude from coal. However, the development of syncrude production has been held

up in part because of the jeopardy to the high investment required for syncrude facilities that would result from possible reductions in crude oil prices below the costs of syncrude.

Additional constraints to development of syncrude production include the availability of capital, availability of water, and the capacity of the construction industry and equipment manufacturers to satisfy the enormous development requirements in the energy field for coal mining, petroleum refineries, electric power plants, and synthetic fuels.

This study is part of an overall ARPA program to determine the energy and mineral resource requirements of the DoD and recommend alternative sources to satisfy these requirements.

Objectives and Scope

The objective of the study is to assess the potential for meeting part of the DoD energy requirements by synthetic petroleum from coal. The results of the study will help in planning DoD strategy in the procurement of synthetic fuels and in indicating the role that DoD can play in furthering the development of the synthetic petroleum industry.

The approach taken in the study to meet this objective was to describe a variety of alternatives for syncrude production, refining, and product mixes. The alternatives cover the several types of syncrude processes, new plants or modifications to existing refineries, and product mixes ranging from DoD product mix requirements to products most compatible with the syncrude properties. The alternative processes are described, material balances are calculated for selected cases, costs of the plants or refinery modifications are estimated, process economics and cost sensitivities are analyzed, plant location considerations are discussed, and constraints are identified. Emphasis is on the relationship of syncrude production to refineries and refinery output.

Summary

DoD Petroleum Consumption

Consumption of petroleum products by DoD averaged 571,000 barrels per day in FY 1974, and the Defense Energy Task Group projected 620,000 barrels per day for FY 1975. As indicated in the following tabulation, jet fuel accounts for the major share of DoD petroleum consumption.

	Percent
Jet fuel	66%
Gasoline	6
Distillates, residuals, and heating fuel	28

About 70 percent of the petroleum is consumed within the coterminous United States, and about two-thirds of that, in the southern half of the country.

Coal Liquefaction

The two principal coal liquefaction processes are the pyrolysis process and the solvent refining, or hydrogenation process. Leading coal liquefaction processes include the COED process in the first category, and the H-Coal, Synthoil, and SRC processes in the second category. The H-Coal process was selected as the most suitable for meeting DoD's petroleum needs. The H-Coal process produces approximately 3 barrels of syncrude, suitable for a refinery feedstock, per ton of coal. The Synthoil and SRC processes are designed for production of heavy fuel oil or utility fuel. The COED process also produces a syncrude suitable as a refinery feedstock but yields only about one barrel of syncrude per ton of coal, with the remaining yield in the form of char.

The conversion of coal to syncrude by the H-Coal process was analyzed for Illinois No. 6 coal, representing a typical high-sulfur eastern bituminous coal produced by underground mining, and Wyoming Powder River coal, representing a low-sulfur western subbituminous coal produced by surface mining. The total capital investment for a syncrude plant with a capacity of 100,000 barrels per day is (in millions of dollars):

Eastern coal	$685
Western coal	$668

The elements of the total syncrude costs in terms of dollars per barrel are given in Table 1, with the total cost set to yield either a 10 percent or a 15 percent discounted cash flow (DCF) after-tax return on investment. It should be possible to obtain financing with a lower rate of return on investment if the risk is reduced, such as by a price guarantee. The federal income tax part of the cost is returned to the U.S. Treasury. Hence, for comparison with the cost of foreign crude, the income tax portion of the syncrude cost should be excluded. The net costs are then substantially below the present delivered price of foreign crude of about $12 per barrel.

Syncrude Refining

Compared with natural crudes, the H-Coal syncrude has more of the lighter fractions. The syncrude is high in aromatics, which makes it valuable for gasoline but requires additional processing for jet fuel.

Several alternative approaches to refining the syncrude were considered. These include:

(1) A new refinery without conversion (cracking) facilities to produce a minimum cost product slate.

(2) A new refinery with conversion facilities to produce the maximum yield of jet fuel.

Table 1

H-COAL SYNCRUDE COST ELEMENTS
(Dollars per Barrel)

Cost Element	Eastern Underground Mined Coal at $9 per ton		Western Surface Mined Coal at $3 per ton	
	15% DCF	10% DCF	15% DCF	10% DCF
Coal	$ 3.43	$ 3.43	$ 1.65	$ 1.65
Other operating costs less credit for by-products	1.63	1.63	2.04	2.04
Investment costs, less taxes	3.81	2.79	3.66	2.67
Subtotal	$ 8.87	$ 7.85	$ 7.35	$ 6.36
Federal income taxes	2.51	1.49	2.42	1.43
Total	$11.38	$ 9.34	$ 9.77	$ 7.79

(3) An existing refinery processing a combination of natural crude and syncrude.

The jet fuel yields for these cases are:

New refinery, minimum cost slate	28%
New refinery, maximum jet fuel	45%
Existing refinery, crude and syncrude	20%

Thus, the jet fuel yields are substantially below the DoD jet fuel proportion, and the gasoline yield is several times as great as the DoD gasoline proportion.

The capital investment, excluding working capital for syncrude, for the new syncrude refineries of 100,000 barrels per day capacity are (in millions of dollars):

Minimum cost slate	$ 95
Maximum jet fuel	$167

The total costs of refining the syncrude for the minimum cost slate are less than the costs of refining natural crude in typical modern refineries which are designed to produce gasoline as the major portion of the output. Maximizing the jet fuel yield increases the refining costs by \$0.36 to \$0.52 per barrel with a 10 percent or a 15 percent, respectively, DCF return on investment, making the costs more comparable with existing crude refineries.

The syncrude could be processed in existing refineries along with natural crude for an additional investment in hydrotreating facilities of approximately 10 percent of the existing refinery investment. The cost of this additional investment is partly compensated by the higher quality of the syncrude. The refining costs for the syncrude are \$0.52 per barrel of product greater than those for refining crude only, with a 15 percent DCF return on investment.

Conclusions

(1) The production of syncrude from coal to supply DoD liquid fuel needs is feasible. Whether the conversion of coal to a refinery feedstock is a desirable part of an overall national strategy for synthetic fuels development is beyond the scope of the study.

(2) Because a reduction in crude prices poses a risk to the syncrude plant investment, some means of reducing the risk, such as a price guarantee, may be necessary to implement syncrude production. Furthermore, reducing the risk would reduce the required return on investment and hence reduce the cost of syncrude.

(3) The estimated syncrude costs are below the current delivered price of foreign crude of about \$12 a barrel. Furthermore, a substantial component of the cost of the syncrude is federal income tax which is returned to the U.S. Treasury.

(4) The H-Coal process produces a syncrude suitable for refinery feedstock. This syncrude may be refined to

conventional fuel products using processes that exist in most modern refineries. However, the jet fuel yield is lower and the gasoline yield is much higher than the proportions of these products in the DoD fuel mix.

(5) The H-Coal syncrude can be refined in a new refinery or along with natural crude in a modified existing refinery at a cost comparable with the cost of refining natural crude.

(6) The distribution of syncrude products directly from DoD dedicated plants to DoD installations would entail substantially higher transportation charges than use of locally procured products.

(7) A likely approach to utilization of syncrude for DoD fuel needs would be to provide a price guarantee for DoD dedicated syncrude plants, to refine the syncrude along with natural crude in existing refineries, and to trade the output for local products in the area of use.

II DoD PETROLEUM CONSUMPTION

Assessment of the potential of syncrude from coal for meeting DoD petroleum needs requires information about DoD petroleum consumption. The principal information sought is the amount of consumption and the product slate (i.e., how much of each type of product is used). Also of interest is the area where the products are used and the area from which procured.

Before presenting data on DoD petroleum consumption, data are given on U.S. refinery inputs and outputs and product imports to place DoD petroleum consumption in perspective.

U.S. Refinery Production and Imports

The petroleum products the United States consumes come principally from U.S. refineries, with a substantial proportion of imported products. The inputs to U.S. refineries come principally from domestic crude, with a substantial proportion of foreign crude and a smaller amount of natural gas liquids. Table 2 gives the breakdown of inputs to U.S. refineries in 1973.

The output of U.S. refineries in 1973 is given in Table 3. (Output is higher than the input because the products have a lower density than the crude and hence are greater in volume.) U.S. refineries are heavily oriented to the production of gasoline, which accounts for nearly half of output.

Product imports for 1973 are also given in Table 3. The total of refinery output and product imports, less product exports of 229,000 barrels per day, represents domestic consumption.

Table 2

U.S. REFINERY INPUTS, 1973[1]*
(Thousands of Barrels per Day)

Domestic crude	9,205
Foreign crude	3,226
Unfinished products	125
Natural gas liquids	815
Total	13,371

Table 3

U.S. REFINERY OUTPUTS AND PRODUCT IMPORTS, 1973[1]
(Thousands of Barrels per Day)

	Refinery Output	Product Imports	Total
Motor and aviation gasolines	6,572	132	6,704
Jet fuel	859	204	1,063
Middle distillates	3,037	383	3,420
Residuals	971	1,701	2,672
All other products	2,413	310	2,723
Total	13,854	2,730	16,583

[1] Monthly Petroleum Statements, U.S. Bureau of Mines (1973).
* Numbered references are also listed at the end of the report.

DoD Petroleum Consumption

The DoD petroleum consumption of 571,000 barrels per day in FY 1974[2] is substantially lower than in previous years and reflects the effect of conservation measures taken in response to the oil embargo, as well as some reduction because of the end of the Vietnam war. In FY1973, before

the oil embargo, petroleum consumption was 236 million barrels, or 646,000 barrels per day. (In FY1973, consumption was 73 percent of the 323.8 million barrels shown in the DFSC Procurement Statistics.[3] The procurement statistics show quantities placed under contract under unfunded open-end contracts and do not show actual barrels used or purchased.) Table 4 gives the projected DoD consumption of petroleum products for FY1975.[2]

Table 4

DoD PETROLEUM CONSUMPTION
(FY1975)

	Thousands of Barrels per day	Percent
Aviation gasoline	15	2.3%
JP-4	329	53.1
JP-5	81	13.0
Auto gasoline	19	3.1
Distillates	82	13.2
Residuals	10	1.5
Heating fuel	84	13.6
Total	620	100.0%

Source: Management of Defense Energy Resources--Phase II, Defense Energy Task Group (1974).

[2] Management of Defense Energy Resources--Phase II, Defense Energy Task Group (1974).
[3] Summary of Procurement Statistics--FY1973, Defense Fuel Supply Center.

As indicated in Table 4, jet fuel accounts for 66 percent of DoD fuel consumption. JP-4, used by the Air Force, accounts for 53 percent of consumption.

DoD petroleum product consumption is only 3.4 percent of total U.S. consumption. However, DoD use of jet fuel amounts to 39 percent of U.S. domestic use.

In the second half FY1974, approximately 70 percent of DoD petroleum product consumption was used in the continental United States (CONUS) and 30 percent overseas.[4] Within CONUS, approximately two-thirds of DoD consumption was in the southern half of the country--Federal Energy Administration regions 3, 4, 6, and 9, bordered by and including the states of Pennsylvania, West Virginia, Kentucky, Arkansas, Oklahoma, New Mexico, Nevada, and California.

Further breakdown of the area of use and the source is derived from the DFSC Procurement Statistics for FY1973, although as previously noted, the procurement statistics do not represent actual use or purchase.

The two major areas of overseas use of petroleum products were (1) the Pacific area, including Hawaii, Central Pacific, Western Pacific, and South and Southeast Asia and (2) Europe and the Mediterranean. The procurement statistics (barrels per day) for these areas for FY1973 show:

Pacific	328,000
Europe and Mediterranean	95,000
Other overseas	38,000

[4] Defense Energy Information System (DEIS-1), RCS: DD-I&L(W)1313, weekly printouts, Defense Supply Agency.

Distribution of the procurement sources for the two overseas areas and CONUS is shown below (In percent);

For the Pacific area	
Pacific area	56%
Middle East	40
For Europe and the Mediterranean	
Europe and Mediterranean	75
Caribbean	23
For CONUS	
CONUS	90
Caribbean	9

These sources do not necessarily reflect origins of the products or crude from which the products were made, but only the area from which they were procured.

DoD Fuel Specifications

Table 5 summarizes the DoD fuel specifications that are particularly important in determining the requirements for refining the syncrude. Although JP-4 accounts for 53 percent of DoD petroleum product consumption, the Air Force is considering switching from JP-4 to JP-8. JP-4 is a naphtha-type fuel while JP-8 is a kerosene type.

Table 5

DoD FUEL SPECIFICATIONS

Aviation Gasoline	
Distillation range (°F)	C_4-338
Vapor pressure (PSIA)	5.5-7
Aviation antiknock (Lean/rich)	80/87-115/145
Tel (ml/gal max.)	0.5-4.6
Sulfur (wt % max.)	0.05
Motor Gasoline (Premium)	
Distillation Range (°F)	C_4-437
Vapor Pressure (PSIA)	11.5
Octane number	
Research (min.)	100
Motor (min.)	90
Tel (ml/gal max.)	4.23
Sulfur (wt % max.)	0.1
Turbine Fuel, JP-4	
Distillation range (°F)	C_5-470
Vapor pressure (PSIA)	2-3
Gravity (°API)	45-57
Aromatics (vol % max.)	25
Luminometer No. (min.)	60
Freeze point (°F)	-76
Sulfur (wt % max.)	0.4
Turbine Fuel, JP-8	
Distillation range (°F)	400-500
Gravity (°API)	39-51
Smoke point (mm min.)	25
Flash point (°F min.)	110
Freeze point (°F max.)	-51
Diesel	
Distillation range (°F)	400-700
Cetane No. (min.)	45
Sulfur (wt % max.)	0.5
Flash point (°F min.)	122
Pour point (°F max.)	-10
Light Fuel Oil	
Distillation range (°F)	400-650
Sulfur (wt % max.)	*
Viscosity (SSU at 100 °F)	32.6-37.9
Flash point (°F min.)	100
Pour point (°F max.)	20
Residual Fuel Oil	
Distillation range (°F-no specification)	650 +
Viscosity (SSU at 100 °F)	900-9000
Flash point (°F min.)	150
Sulfur (wt % max.)	*

*EPA federal maximum corresponds to 0.7 wt % (max.) for residual fuel oil, while many local regulations limit the sulfur content to 0.2 wt % for No. 2 fuel oil and 0.3 wt % for residual fuel.

III COAL LIQUEFACTION PROCESSES

Background

Commercial experience on processes for converting coal to liquid fuels has been limited. Gasoline was produced from coal in Germany during the late 1920s and 1930s by hydrogenation of coal tar and by the Fischer-Tropsch process. The latter process currently is being used in the South African SASOL plant to produce gasoline and other liquid products from synthesis gas ($CO + H_2$) generated in Lurgi coal gasifiers. Since coal liquefaction processes are inherently expensive and thermally inefficient, commercial interest has been limited while the price of petroleum crudes remained low. Rapidly rising petroleum prices and the possibility of restricted crude supplies have recently increased the research and development effort to commercialize new coal liquefaction processes. The present research effort in the United States is directed toward developing new processes that will operate at less severe conditions than those used in the earlier processes, thereby improving the efficiency as well as the technical and economic feasibility.

Conversion of coal to liquid fuels basically entails reducing the carbon to hydrogen weight ratio of the coal, either by adding hydrogen or by removing part of the carbon as coke or carbon dioxide. Most bituminous coals have a C/H weight ratio in the range of 11 to 15. The following tabulation indicates the approximate reduction in C/H weight ratio necessary to produce useful liquid fuels.

	C/H Weight Ratio
Bituminous coal	11-15
Heavy fuel oil	7.4-8
Light fuel oil	6.2-6.5
Jet fuel	5.8-6.1
Gasoline	5.5-6.0

In addition to the problem of reducing the C/H weight ratio, coal has a number of chemical and physical characteristics that greatly complicate its conversion to liquid fuels. For example, handling coal solids during transportation and processing is much more difficult than pumping liquid petroleum or natural gas. Coal contains very high molecular compounds that must be cracked to lighter fractions, plus appreciable quantities of water, ash, and compounds containing sulfur, oxygen, and nitrogen that must be severely reduced to produce useful fuels.

Basic Processes

Four basic processing routes have been extensively investigated for converting coal to liquid fuels:

- Solvent refining--coal is dissolved in recycle solvent and moderately hydrogenated (usually noncatalytically) at 1000 psi pressure and temperature of 700° to 825°F. The product is a clean semisolid fuel suitable for utility boilers or to be further upgraded to heavy fuel oil.
- Coal pyrolysis or carbonization--in a process similar to coking of coal, coal volatiles are cracked and removed at a temperature of 1400° to 1600°F and low pressure. Products include gases, heavy crude oil that can be upgraded by further hydrotreating, and large amounts of coal char.
- High pressure hydrogenation--coal is extensively hydrogenated (catalytically) at high pressure (2000 to 4000 psi) and moderately high temperature (825° to 1000°F). Product is a

good quality syncrude suitable for further upgrading to lighter products in a conventional refinery. Investment and operating costs are relatively higher than solvent refining or coal pyrolysis.

- Fischer-Tropsch synthesis--coal is gasified with oxygen and steam to CO and H_2 synthesis gas, which is then catalytically converted to liquid hydrocarbons. The SASOL plant produces largely gasoline plus small amounts of other products. Investment and operating costs are high for this process and thermal efficiency is low.

The above processes are listed roughly in order of their capability to produce light products. Thus, the solvent refined coal (SRC) process produces a high melting semisolid fuel, while the Fischer-Tropsch has gasoline as its principal product. The processes are also listed in order of processing severity and increasing investment and operating costs. In general, production of light fuels from coal requires large volumes of hydrogen, higher temperatures, and pressures that result in lower conversion efficiencies and higher costs.

Major Coal Liquefaction Technologies

Numerous coal liquefaction processes have been proposed or evaluated in bench scale equipment, while relatively few processes have reached the pilot plan stage. Since it is not feasible to describe all these processes, only the most promising and those in the more advanced state of development will be discussed. The leading coal liquefaction processes with their principal product and present status of development are summarized in Table 6.

Solvent Refined Coal Process

Work on the solvent refined coal (SRC) process was initiated in the early 1960s by Spencer Chemical as a method for de-ashing coal. Development efforts were later taken over by the Pittsburg and Midway Coal

Table 6

PRESENT STATUS OF COAL LIQUEFACTION PROCESSES

Process	Developer	Approximate Liquid Product Yield (barrels per ton dry coal)	Present Status
Solvent Refined Coal (SRC)	Pittsburg and Midway	2.5 - 3--semisolid utility fuel	OCR-sponsored pilot plant (75 T/D) being constructed in Tacoma, Washington, to produce 150 B/D SRC product. Southern Services - EPRI sponsored 6 T/D pilot plants in Birmingham to produce 18 B/D SRC product. Both pilot plants will start up on Kentucky No. 14 coal. OCR has issued RFP to construct large demonstration SRC plant.
COED	FMC Princeton, New Jersey	0.7 - 1.3--syncrude	OCR-sponsored 36 T/D pilot plant operated successfully to produce 40 B/D syncrude and 18 T/D coal char. FMC now seeking support for COGAS process to produce syncrude and pipeline gas.
CSF	Consolidation Coal Cresap, West Virginia	2 - 2.5--heavy fuel oil, or syncrude	OCR-sponsored 25 T/D pilot plant shut down in 1970. [illegible] reactivated in 1974 for coal liquefaction unit operation studies. Exxon and Old Ben Coal have announced similar processes.
Synthoil	Bureau of Mines Pittsburg, Pennsylvania	3--heavy fuel oil	Bureau of Mines completed successful bench scale tests on 10 lb/hr unit. Now seeking industry participation in 8 T/D pilot to produce 24 B/D low sulfur fuel oil.
Fischer-Tropsch	South African Coal, Oil, and Gas (SASOL) Union of South Africa	1.5--gasoline	Commercial plant produces 7,000 B/D gasoline plus minor amounts of other products. Operational since 1965. Uses Lurgi gasifiers to produce CO and H_2 synthesis gas. Kellogg synthesizers reactors to produce polymer gasoline.
H-Coal	Hydrocarbon Research Trenton, New Jersey	2.6 - 3.2--syncrude	OCR-sponsored 3 T/D pilot plant that produced 10 B/D syncrude. Development being continued by six commercial sponsors; OCR now negotiating with HRI to construct 250-700 T/D pilot plant.

Mining Company (subsidiary of Gulf Oil Corporation). The process was previously called the PAMCO process, but the name was later changed to the SRC process.

The objective of the SRC process is to produce a clean low-sulfur fuel that would meet environmental regulations and could be burned in electric utility or industrial boilers. The product is a semisolid, low-ash, low-sulfur fuel suitable for steam boilers but not as a refinery feedstock. Considerably more processing would be required to upgrade the SRC product to a syncrude refinery feedstock.

Figure 1 is a block flow diagram of the SRC process. Coal entering the process is dried, crushed to 1/8 inch, and slurried with twice its weight of process derived solvent that boils between 400° and 850°F. The coal is partly dissolved in the solvent and pumped along with the required hydrogen into the SRC reactor operated at 1000 psig and 825°F.

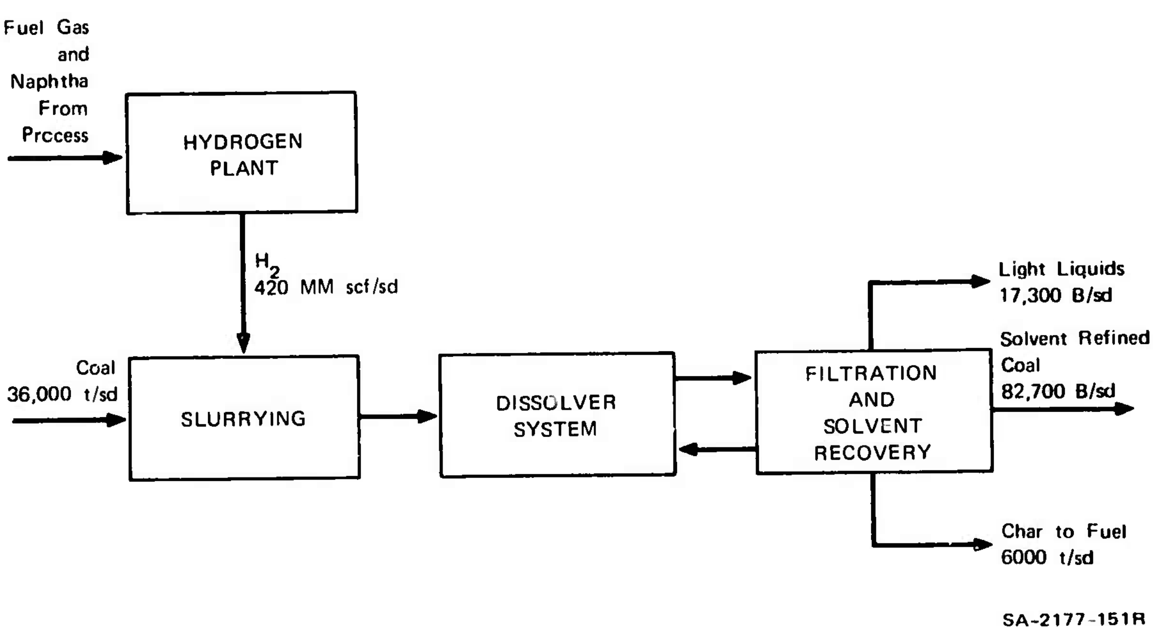

FIGURE 1 SRC PROCESS FOR UPGRADING COAL TO A SEMISOLID CLEAN UTILITY FUEL

While the process is nominally noncatalytic and no catalysts are added to the hydrogenation reactor, alkali metal and iron compounds in the coal ash act catalytically to increase the hydrogenation reaction rate. From 85 to 95 percent of the carbonaceous material in the coal is converted to liquids in the reactor. Product from reactor is filtered to remove the undissolved coal and ash, and the resulting liquid is fractionated to recover the process solvent and SRC product.

Char from the SRC process is high in ash, contains only about 30 percent carbon, and will require sulfur removal facilities when used as a fuel. The SRC product melts between 250° and 350°F and contains 0.1 percent ash, 1 to 0.3 percent sulfur, 3.7 percent oxygen, and 1.8 percent nitrogen, which makes it suitable as boiler fuel but not as refinery feedstock. Yield from the SRC process per ton of dry coal is 0.6 barrel of C_5 to 450°F light oil and 2.7 barrels of +450°F SRC product.

COED Process

An example of the coal pyrolysis liquefaction processes is the Char-Oil-Energy Development (COED) process being developed by FMC Corporation in Princeton, New Jersey, under an Office of Coal Research contract. Figure 2 is a block flow diagram of the COED process, which is based on FMC's previous experience with a fluidized-bed process for producing metallurgical coke.

Bituminous coal entering the process is dried at 400°F and ground to a -16 mesh. The coal is then exposed to progressively higher temperatures in four stages of fluidized bed pyrolyzers and exits the fourth stage at 1600°F. Coal is retained in the pyrolyzers for 60 minutes, requiring large volume pyrolyzers. Heat and gas required in the pyrolyzers are developed by burning part of the char with oxygen in the fourth stage pyrolyzer. Oil and gas exits the second stage pyrolyzer, and the oil is condensed to a tar like crude coal oil.

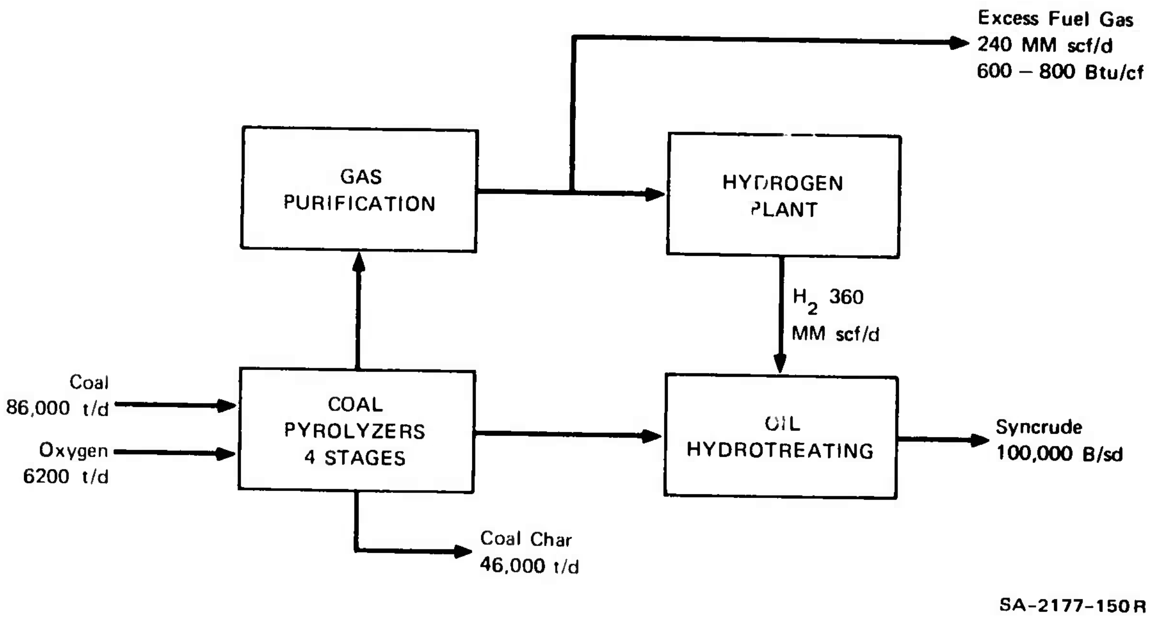

FIGURE 2 COED PROCESS FOR COAL LIQUEFACTION TO SYNCRUDE

Sulfur compounds are removed from the process gas stream, and part of the purified gas is steam reformed to provide hydrogen required to hydro-treat the crude coal oil to syncrude. The hydrotreating step adds hydrogen to the oil, thereby increasing the yield of light fractions and simultaneously reducing undesirable sulfur, oxygen, and nitrogen containing compounds. Yields of syncrude from the COED process depend on the coal being processed and vary from 0.7 to 1.3 barrels of syncrude per ton of coal. The remainder of the process gas could be marketed as a fuel gas or reformed to additional hydrogen for other uses.

A major disadvantage of the COED process is that about one-half the coal entering the process exits the fourth stage pyrolyzer as coal char. Since the char is very low in volatiles and contains about the same amount of sulfur as the original coal, it may be unacceptable as a utility fuel.

To solve this problem, FMC is now developing the COGAS process that will produce syncrude amd gasify the char to pipeline quality gas.

Other coal pyrolysis liquefaction processes that are being developed include the TOSCOAL process by Oil Shale Corporation and flash pyrolysis of coal by Garrett Research and Development.

Consolidation Synthetic Fuels (CSF) Process

The CSF process was developed during the 1960s by Consolidation Coal Company (now a subsidiary of Continental Oil Company) under an OCR contract. The process was later investigated as "Project Gasoline" in a 25 ton-per-day pilot plant at Cresap, West Virginia. Numerous mechanical problems were encountered and the pilot plant was shut down in 1970. OCR has recently reactivated the plant and plans to utilize it to investigate components of coal liquefaction processes such as filters or lock hoppers.

The CSF process differs from direct hydrogenation processes such as SRC in that hydrogen is added to the coal via a hydrogen donor solvent. The donor solvent is a coal-derived extract containing compounds such as tetralin and is regenerated and recycled within the process.

Briefly, the CSF process first dissolves coal in the donor solvent at pressure of 250 to 350 psi and a temperature of 750° to 800°F. The slurry is then filtered to remove the unreacted coal and ash and the liquid extract is water washed. The extract is further upgraded by catalytically hydro-cracking in an ebullating bed reactor at 4200 psi and 825°F to produce a medium quality syncrude.

The hydrogen donor solvent approach to coal liquefaction reportedly will be used in two other proprietary processes. Exxon has operated a 0.5 ton-per-day pilot plant that uses a donor solvent and catalytic regeneration of the solvent external to the liquefaction reactor. The

process can produce either a low-sulfur fuel oil or syncrude suitable for refinery feedstock. Details are limited on the Exxon process but the company is reported to be planning to construct a 200 to 300 ton-per-day pilot plant in Baytown, Texas.

Recently, another hydrogen donor coal liquefaction development was announced by Old Ben Coal Company (part of Standard Oil Company of Ohio). The company plans a five-year, $73 million program to construct a 900 ton-per-day donor pilot plant in Toledo, Ohio, that could either produce a solvent-refined coal type of product or upgrade the coal to syncrude. Support for the program is now being solicited from other industrial companies and government agencies.

Synthoil Process

The Synthoil process being developed by the Bureau of Mines is an example of high-pressure catalytic hydrogenation, and its objective is to convert coal to a heavy low-sulfur fuel oil that could be burned in utility or industrial boilers.

A block flow diagram of the process is presented in Figure 3. High-sulfur bituminous coal is dried, ground to -100 mesh, and slurried with twice its weight of recycle oil produced in the process. The slurry mixture is pumped along with the required hydrogen into a fixed-bed catalytic reactor operated at 2000 to 4000 psi and 800° to 850°F. The Co-Mo fixed-bed catalyst is in the form of 1/8- to 1/4-inch cylinders, and the cool solvent hydrogen mixture is moved through the bed at 6 feet per second to generate turbulence in the mixture and prevent bed plugging. The combination of high hydrogen partial pressure, turbulence, and catalyst reduces the required retention time in the reactor to about 1 to 2 minutes. Ninety percent of the coal is converted to a heavy fuel oil containing less than 0.3 percent sulfur, thus meeting most environmental specifications.

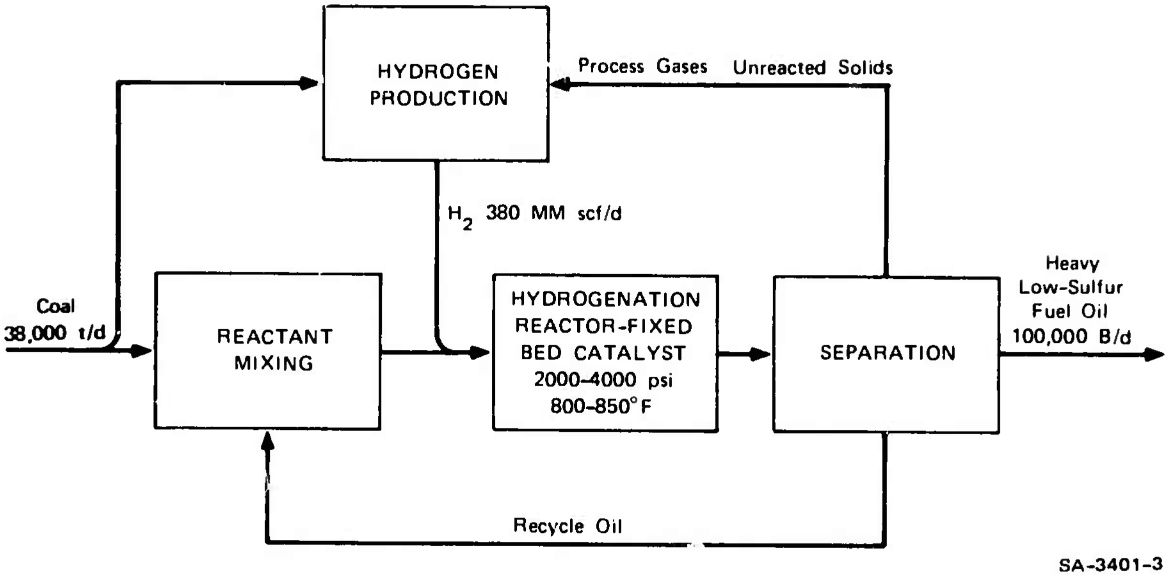

FIGURE 3 SYNTHOIL PROCESS FOR CONVERTING COAL TO CLEAN FUEL OIL

The Bureau of Mines is planning to separate the unreacted solids and product liquid by either a rotary pressure filter or continuous centrifuge. It should be pointed out that separation of solids (ash and unreacted coal) from the liquid product has been one of the most serious operational problems encountered in all coal liquefaction processes with the possible exception of the Fischer-Tropsch process.

The Bureau has reported slight reductions in catalyst activity over 40-day runs and no catalyst caking below 875°F. The Synthoil process has completed bench scale investigations, and the Bureau is now planning to construct an 8 ton-per-day pilot plant.

H-Coal Process

The H-Coal process is a high pressure catalytic hydrogenation process designed to convert coal to syncrude that would be suitable as a refinery

feedstock. In addition, the process can be designed so that it generates little or no coproducts such as coal char or heavy tars that present disposal or marketing problems. Since the primary objective of this study was production of light products for DoD use, such as gasoline, jet fuel, and distillate from coal syncrude, the H-Coal process appeared to be the most suitable process of the coal conversion processes now being developed and therefore was selected as the base case to be evaluated in depth.

The H-Coal process has been under development since the early 1960s by Hydrocarbon Research in Trenton, New Jersey. The initial development work was sponsored by the Office of Coal Research and is being continued by six oil and coal companies. Recently, OCR indicated it may renew sponsorship of the process.

Details on the H-Coal process for producing refinery grade syncrude from typical eastern and western coals are given in the following section.

IV SYNCRUDE FROM EASTERN AND WESTERN COAL BY THE H-COAL PROCESS

Representative Eastern and Western Coals

The technical and economic aspects of converting eastern and western coals to refinery grade syncrude were analyzed in depth in two base cases. Illinois No. 6 coal was selected as a typical high-sulfur eastern bituminous coal that would be produced by underground mining methods; Wyoming Powder River coal was selected as a low-sulfur western subbituminous coal having thick bed seams that would be recovered by aboveground mining methods. In both cases, proven resources of these coals are sufficiently large to support a liquefaction facility over a 20-year production period. The analysis of the selected coals is given in Table 7.

H-Coal Process Flows

Figure 4 is a block flow diagram of the H-Coal process for converting Illinois No. 6 coal to syncrude, and the flow sheet of the western coal case is shown in Figure 5. Details on mass flows in the streams within the plants are given in Tables 8 and 9.

Inspection of Figures 4 and 5 and Tables 7 and 8 indicate differences encountered in processing eastern and western coals to syncrude. First, the as-received subbituminous western coal has a much higher moisture content than the eastern bituminous coal. This means that more western coal must be mined and additional water removed before the coal enters the process. The western coal also generally consumes more hydrogen during the conversion step than eastern coal; while the western coal contains less sulfur and nitrogen, which consumes less hydrogen, that effect is more than

Table 7

CHARACTERISTICS OF REPRESENTATIVE EASTERN AND WESTERN COALS

	Illinois No. 6 Bituminous Coal			Wyoming Powder River Subbituminous Coal		
	As-Received	MF* Basis	MAF† Basis	As-Received	MF Basis	MAF Basis
Proximate analysis (wt%)						
Moisture	10			33		
Volatiles	32	36		29.7	44.3	
Fixed carbon	49	54		31.5	47.0	
Ash	9	10		5.8	8.7	
Total	100	100		100	100	
Ultimate analysis (wt%)						
Moisture	10			33		
Ash	9	10.0		5.8	8.7	
Carbon	62.7	69.7	77.5	45.7	68.2	74.7
Hydrogen	4.8	5.3	5.9	3.2	4.8	5.2
Oxygen	8.9	9.9	11.0	11.1	16.6	18.2
Sulfur	3.5	3.9	4.3	0.5	0.7	0.8
Nitrogen	1.1	1.2	1.3	0.7	1.0	1.1
Total	100	100	100	100	100	100
Higher heating value (Btu/lb)	11,000	12,200		7,800	11,680	

*Moisture free.

†Moisture ash free.

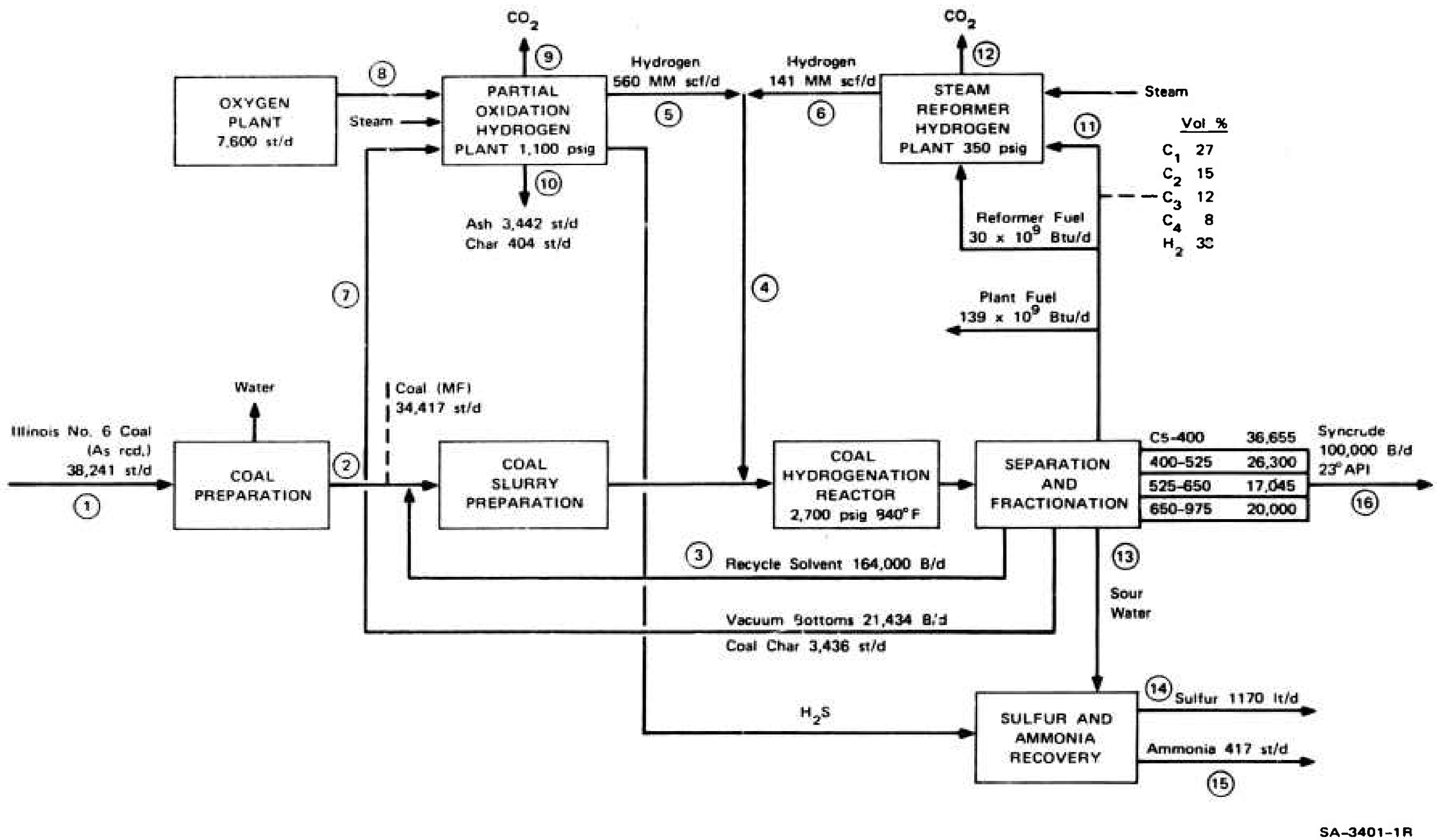

FIGURE 4 FLOW DIAGRAM FOR SYNCRUDE FROM ILLINOIS NO. 6 COAL BY THE H-COAL PROCESS

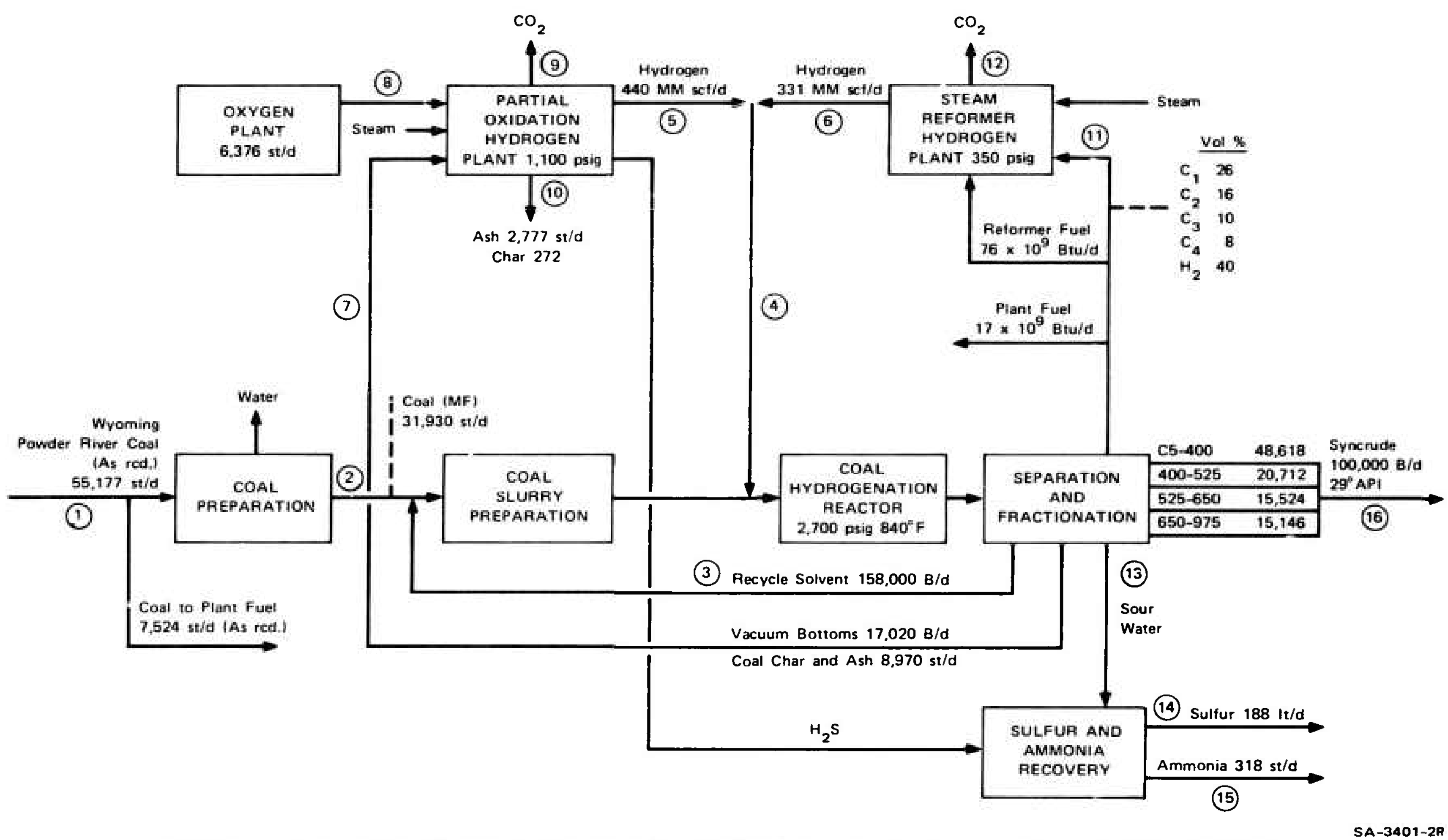

FIGURE 5 FLOW DIAGRAM FOR SYNCRUDE FROM WYOMING POWDER RIVER COAL BY THE H-COAL PROCESS

Table 8

STREAM FLOWS FOR SYNCRUDE FROM ILLINOIS NO. 6 COAL BY THE H-COAL PROCESS
(Basis: 100,000 B/D Syncrude)

Stream Number	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)	(14)	(15)	(16)	
	10^3 lb/hr	10^3 lb/hr	wt%	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	lb mol/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	°API
Coal (as received)	2,869																		
Coal (MF basis)																			
C		1,998	69.7																
H		152	5.3																
O		284	9.9																
S		111.8	3.9																
N		34.4	1.2																
Ash		289	10.0								289								
Coal char								287.7			33.7								
Water	318														272.4				
C_1												14.8	927						
C_2												15.9	530						
C_3												18.5	422						
C_4												16.9	292						
C_5																			
400°F																		429.8	44
400-525°F																		352.0	22
525-650°F																		241.3	14
650-975°F				2,476														301.7	5
975+°F								345.3											
H_2					156.2	122.8	33.4					2.3	1,316						
O_2									659										
CO_2										1,910				210.5					
H_2S															90.2				
NH_3															34.7		34.7		
Sulfur																84.8			
Total	3,187	2,869.2	100.0	2,476	156.2	122.8	33.4	633.0	659	1,910	322.7	68.4	3,487	210.5	397.3	84.8	34.7	1,324.8	

Table 9

STREAM FLOWS FOR SYNCRUDE FROM WYOMING POWDER RIVER COAL BY THE H-COAL PROCESS
(Basis: 100,000 B/D Syncrude)

Stream Number	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)	(14)	(15)	(16)	
	10^3 lb/hr	10^3 lb/hr	Wt%	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	lb mol/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	°API
Total coal (as received)	3,081																		
Reaction coal (MF basis)																			
C		1,815	68.2																
H		128	4.8																
O		442	16.6																
S		18.6	0.7																
N		26.6	1.0																
Ash		231.5	8.7					231.5			231.5								
Oxygen									531.5										
Coal char								242			22.7								
Water	1,517														427				
C_1												35.8	2,236						
C_2												42.9	1,432						
C_3												39.0	886						
C_4												38.0	654						
C_5-400°F																		535	48
400-525°F																		269	27
525-650°F																		212	19
650-975°F				2,350														225	8
975+°F								274											
H_2					176.4	96.6	79.8					7.1	3,553						
CO_2										1,558				457					
H_2S															13.6				
NH_3															26.5		26.5		
Sulfur																17.2			
Total	4,598	2,661.7	100.0	2,350	176.4	96.6	79.8	747.5	531.5	1,558	254.2	162.8	8,761	457	467.1	17.2	26.5	1,241	

offset by the high oxygen content in the western coal that must be removed by reacting with hydrogen to form water. The amount of ash is lower in the western coal case, and it can generally be returned to the worked out surface mine, which reduces the problems of ash handling and disposal not possible with ash disposal in eastern locations.

The sequence of operations in the H-Coal process is briefly as follows. Coal feed is first ground to -40 mesh, dried, and slurried with an equal weight of coal-derived solvent. The coal slurry is then heated and pumped with hydrogen into the bottom of an ebullating bed reactor where it contacts a Co-Mo catalyst. The reactor operates at 2700 psig and 840°F with a coal feed rate of 30 to 90 pounds per hour per cubic foot of reactor volume. The catalyst is retained in the reactor, and the upward hydrogen flow acts to provide good contact between the coal, liquid, and catalyst. The catalyst is removed periodically from the reactor for reactivation.

Long retention times in the reactor result in lighter products, with an attendant greater consumption of hydrogen. Hydrogen consumption can vary from 16,000 to 21,000 scf per ton of dry coal when producing syncrude compared with 8,000 to 10,000 scf per ton when a heavy low-sulfur fuel oil is produced.

Product liquid and process gases generated during hydrogenation exit from the top of the reactor and are separated in a series of flash drums and fractionation units. Separation of unreacted solids and product liquids is a problem in H-Coal as it is in all other coal liquefaction processes. Although filtering, centrifuging, and coking have been evaluated satisfactorily for separating solids from the product liquid, a number of physical and environmental problems are connected with these separation methods. It now appears that the most feasible approach is to fractionate the mixture from the reactor and send the combined unreacted solids and vacuum bottoms to a partial oxidation unit for the production of hydrogen.

The remaining hydrogen is generated by steam reforming the C_1 to C_4 process gases generated in the reactor.

Compounds containing sulfur, nitrogen, and oxygen in the feed coal are largely converted to hydrogen sulfide, ammonia, and water in the reactor and removed as sour water in the separation step. The ammonia is recovered by steam stripping, and can be marketed for fertilizer. Additional hydrogen sulfide formed in the hydrogen partial oxidation unit is combined with the H_2S from the reactor and sent to a Claus plant for conversion to elemental sulfur. The Claus plant is equipped with tail gas scrubbing facilities to limit sulfur emissions within environmental regulations.

Utilities and Labor

Utilities and labor required in a coal liquefaction plant are a significant part of the process economics. Indicated below are the utilities and plant operating labor requirements of H-Coal plants producing 100,000 barrels per day of syncrude from eastern and western coals.

	Illinois No. 6 Coal	Wyoming Powder River Coal
Electric power (kW)	131,000	144,000
Cooling water (gpm)	522,000	510,000
Boiler feed water (gpm)	4,200	4,980
Steam (1,000 lb/hr)	2,800	2,175
Raw water (gpm)	18,000	20,300
Plant operators (men/shift)	99	102

H-Coal Syncrude Properties

The properties of syncrude from representative eastern and western coals are given in Tables 10 and 11. Composition of the syncrudes was estimated from information previously published on the H-Coal process

Table 10

PROPERTIES OF H-COAL SYNCRUDE FROM ILLINOIS NO. 6 COAL

	Distillation Range				
	C_5-400°F	400-525°F	525-650°F	650-975°F	C_5^+ Syncrude
Net yield (vol%)	36.7	26.3	17	20	100
Elemental analysis (wt%)					
Carbon	85.3	86.4	87.3	88.9	86.8
Hydrogen	13.0	11.4	10.2	7.8	10.9
Oxygen	1.5	1.9	2.09	2.4	1.9
Sulfur	0.1	0.14	0.20	0.4	0.19
Nitrogen	0.15	0.15	0.23	0.5	0.23
C/H ratio	6.56	7.72	8.56	11.39	7.96
Hydrocarbon type analysis (vol%)					
Paraffins	12	13	15	5	
Olefins	--	--	--	--	
Naphthenes	65	52	37	20	
Aromatics	23	35	48	75	
Gravity (°API)	44	22	14	5	23
Specific gravity	0.8063	0.920	0.972	1.0366	0.9159
Weight (lb/gal)	6.7	7.65	8.09	8.62	
BP midpoint	250	463	588	813	537
UOP K-factor	11.04	10.60	10.49	10.42	10.91

Table 11

PROPERTIES OF H-COAL SYNCRUDE FROM WYOMING POWDER RIVER COAL

	Distillation Range				
	C_5-400°F	400-525°F	525-650°F	650-975°F	C_5+ Syncrude
Net yield (vol%)	48.6	20.7	15.5	15.2	100
Elemental analysis (wt%)					
Carbon	84.7	86.1	86.8	88.1	86.0
Hydrogen	13.5	11.6	10.3	8.0	11.6
Oxygen	1.6	2.1	2.4	3.2	2.1
Sulfur	0.08	0.1	0.13	0.2	0.11
Nitrogen	0.15	0.19	0.27	0.5	0.23
C/H ratio	6.27	7.42	8.43	11.0	7.41
Hydrocarbon type analysis (vol%)					
Paraffins	20	24	14	10	--
Olefins	--	--	--	--	--
Naphthenes	64	48	46	30	
Aromatics	16	28	40	60	
Gravity (°API)	48	27	19	8	29
Specific gravity	0.788	9.893	0.940	1.014	0.881
Weight (lb/gal)	6.56	7.43	7.83	8.45	7.32
BP midpoint	250	463	588	813	
UOP K-factor	11.36	10.92	10.75	9.94	

during the period when the process was under OCR sponsorship and from recent papers by Hydrocarbon Research on the process.[5,6,7] Currently, the process is receiving commercial support, and data on product compositions from specific coals are largely proprietary.

In general, syncrudes from coal are high in aromatics compared with petroleum crudes, and syncrude from eastern coal is more aromatic than western coal. While aromatics can be beneficial in producing gasoline, they present problems when producing jet or diesel fuel. This problem will be covered in depth in the refining section.

H-Coal Process Thermal Efficiency

The overall thermal efficiency of converting coal to syncrude is defined as the heating value of all product fuels divided by total heating value in the feed coal to the process, including plant fuel but not including electric power. The thermal efficiency of producing syncrude was 71 percent in the Illinois No. 6 coal case and 75 percent in the Wyoming Powder River coal case.

Investment and Operating Costs for H-Coal Facilities

The estimated plant facilities investment for an H-Coal plant capable of producing 100,000 barrels of syncrude per day is given in Table 12. Total plant facilities investment for Illinois No. 6 coal is estimated at $533 million. Also included in Table 12 are the investment in land, plant working capital, start-up expenses, paid-up royalties, and interest during construction giving a total capital investment of $685 million or $20.85 per annual barrel of syncrude, based on 328.5 production days per year.

The most significant plant investment is that required to produce the necessary hydrogen. Sections of the plant that are devoted to hydrogen production include the steam reformer section, partial oxidation unit,

Table 12

CAPITAL INVESTMENT FOR H-COAL SYNCRUDE PRODUCTION
(Basis: 100,000 B/SD Syncrude Production)

	Millions of Dollars	
	Illinois No. 6 Coal	Wyoming Powder River Coal
Plant facilities		
Coal storage, handling, and preparation	$ 33	$ 46
Coal slurry preparation	13	13
Coal hydrogenation	112	123
Product separation and fractionation	35	35
Steam reformer hydrogen plant	26	44
Partial oxidation hydrogen plant	157	128
Oxygen plant	68	59
Sulfur and ammonia recovery	25	13
Utilities	53	55
General plant facilities	11	11
Total plant facilities investment	$533	$527
Land cost	1	1
Plant working capital	27	18
Organization and start-up costs	32	32
Paid-up royalties	17	16
Interest during construction	75	74
Subtotal	$152	$141
Total capital investment	$685	$668

oxygen plant, and part of the plant utilities. Investment in hydrogen facilities* totals $276 million out of the $533 million total plant facilities, or 52 percent.

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*Steam reformer hydrogen plant, partial oxidation hydrogen plant, oxygen plant, and part of the general plant facilities.

The investment required by coal liquefaction plants is determined to a considerable degree by the assumptions made regarding the source of feed used for hydrogen production and the type of fuel used in the plant. It was assumed in this study that hydrogen would be produced largely from vacuum bottoms and unreacted coal char recovered from the separation and fractionation section. A smaller amount of hydrogen is produced from the process gas that is generated in the hydrogenation step, and the process gas is also utilized for all plant fuel. Thus, the plant is designed to meet federal emission regulations regarding plant fuel, it consumes only coal as a feedstock, and it produces syncrude as its sole product.

Investment in the coal liquefaction plant can be reduced if alternative feedstocks, fuel, and product slates are assumed. For example, the hydrogen plant investment could be halved if it were assumed that natural gas or naphtha is reformed to hydrogen. Similarly, the use of coal as plant fuel and producing char as a by-product would reduce the investment. However, it was felt that each of these alternatives was unacceptable and unrealistic in view of present and future competitive fuel demands and environmental control regulations.

The plant investment for syncrude from western Wyoming Powder River coal is also shown in Table 12. The western coal case requires a higher investment in the coal handling and preparation section because of the amount of coal that must be processed and the high moisture content in the incoming coal. Hydrogen production facilities again are the most significant investment, totaling \$251 million out of \$527 million for all plant facilities. Total capital investment is \$668 million, or \$20.33 per annual barrel of syncrude.

Table 13 summarizes the estimated annual operating costs for 100,000 barrels per day of H-Coal syncrude. For eastern coal, the operating costs, excluding capital costs and coal costs are \$75 million per year or \$2.28

Table 13

ANNUAL OPERATING COSTS FOR H-COAL SYNCRUDE PRODUCTION
(Basis: 100,000 Barrels per Stream Day)

	Millions of Dollars	
	Illinois No. 6 Coal	Wyoming Powder River Coal
Labor		
Operating labor and supervision	\$ 5.74	\$ 5.85
Maintenance labor	6.93	7.90
Payroll burden and G&A overhead	7.09	7.20
Total labor	\$19.75	\$21.45
Raw materials and supplies (excluding coal)		
Catalysts and chemicals	10.37	11.84
Maintenance supplies	10.66	10.54
Total raw materials and supplies	\$21.03	\$22.38
Electric power at 1.25¢/kWh	12.88	14.11
Fixed costs		
Plant overhead	10.66	10.54
Property taxes and insurance	10.66	10.54
Total fixed costs	\$21.32	\$21.08
Total operating costs, excluding coal	\$74.99	\$79.02

per barrel of syncrude. The annual operating costs for the western coal case are \$79 million, or \$2.40 per barrel of syncrude exclusive of capital costs.

Coal prices and capital costs are the most important factors in determining syncrude prices, and sensitivity studies of these factors are presented in Section VII. Details on the economic bases used in preparing the estimated operating costs are also given in that section.

V SYNCRUDE REFINING

Introduction

In common with the refining of conventional petroleum feedstocks, syncrude refining entails the transformation of a complex raw material mixture into a number of fuel products. The quality specifications of these products are determined primarily by their end uses, such as in spark-ignited piston engines (gasoline), compression-ignited piston engines (diesel), or turbine engines (jet). In recent years, the increasing concern for air quality has brought about the implementation of fuel quality requirements in addition to and in many cases in conflict with the fuel qualities required for engine performance. The characteristics of syncrudes from coal, although generally similar to those of natural petroleum, differ from petroleum primarily in their higher content of aromatic molecules and in their higher content of nitrogen and oxygen compounds. In the following discussion, the importance of the unique characteristics of coal syncrudes is analyzed in detail, followed by the development of several specific cases of producing DoD products from syncrude.

Syncrude Characteristics

The characteristics of syncrudes vary significantly from one coal source to another, even from the same conversion process. From different coal conversion processes, the liquid product qualities vary over a wide range, especially in the relative amounts of material in the various distillation ranges. The H-Coal process, as discussed previously, was selected for this study on the merits of its product similarity to petroleum.

For orientation on the issue of syncrude refining, it is useful to compare the qualities of the H-Coal syncrude with those of a natural petroleum. For this illustration, we have selected a high-quality east Texas crude (38°API, 0.33 weight percent sulfur). In Table 14, this east Texas crude is compared with H-Coal syncrude on the basis of its primary distillation yields, gravity in degrees API, characterization factor, and sulfur content. One of the most salient differences is the absence of the 975°F+ residuum in the syncrude. In a typical petroleum refinery, a significant part of the process facilities may be devoted to upgrading the residuum fraction, especially if the crude is high in sulfur.

Table 14

COMPARISON OF NATURAL CRUDE
AND H-COAL SYNCRUDE

	Distillation Yields (volume percent)	
	East Texas Crude	H-Coal Syncrude*
Fractions		
C_5-400°F (gasoline)	40%	37%
400-515 (kerosene)	14	26
525-650 (heating oil)	12	17
650-975 (fuel oil)	20	20
975+	14	—
	100%	100%
Gravity, °API	38	23
Characterization factor	11.89	10.14
Sulfur, weight percent	0.33	0.19

*From Illinois No. 6 coal.

Of particular significance to meeting the DoD jet fuel requirements is the high yield of 400° to 525°F (kerosene) material from syncrude. The 26 percent yield of kerosene from syncrude is nearly twice the typical yield from petroleum, but is still less than half the yield needed to meet the DoD jet fuel proportion.

However, the volume yields of the various fractions are only the first step in analyzing the refining requirements of the syncrude. The chemical nature of the various fractions is also critical. Ideally, the gasoline fraction (C_5-400°F) would be highly aromatic for a high octane rating. The kerosene and diesel boiling range material would be non-aromatic for high smoke point and cetane ratings, respectively. As was shown in Table 10, the H-Coal syncrude is much closer to the ideal for gasoline than for jet fuel and diesel. The high naphthene content of the gasoline fraction may be readily converted to aromatics with catalytic reforming, an operation that yields a substantial quantity of hydrogen as a by-product. This has a significant economic impact, as will be shown in the study cases.

The kerosene, or material in the 400° to 525°F boiling range, is also high in aromatics, which corresponds to a relatively low hydrogen content of 11.4 weight percent. From correlations developed by the Air Force Aero Propulsion Laboratory[8] at Wright-Patterson Air Force Base, the minimum hydrogen content should be 13.5 weight percent to meet the specifications for JP-8 jet fuel. Thus, incremental hydrogen on the order of 2 percent must be added to this fraction. Hydrogen is also consumed in reducing nitrogen, oxygen, and sulfur to acceptable levels.

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[8] C. R. Martell and L. C. Angello, "Hydrogen Content as a Measure of the Combustion Performance of Hydrocarbon Fuels," Technical Report AFAPL-TR-72-103, Air Force Aero Propulsion Laboratory, USAF, Wright-Patterson AFB, Ohio (May 1973).

Similarly, a large quantity of hydrogen addition would be required to upgrade the 525° to 650°F material to meet the diesel cetane number requirement. However, since the material in this boiling range is also consumed in substantial quantity for space heating as No. 2 fuel oil, it does not appear necessary to upgrade all this material to diesel fuel.

Although the 0.2 weight percent sulfur content meets most sulfur specifications for No. 2 fuel oil, some hydrotreating will be required to reduce the oxygen and nitrogen to acceptable levels.

The heaviest part of the syncrude, the 650° to 975°F fraction, falls into the category of residual fuel oil for boiler firing or gas oil for cracking to lighter products. The 0.4 weight percent sulfur content of this material is well within the EPA federal standard of 0.7 weight percent maximum sulfur. However, the nitrogen content of 0.5 weight percent might result in excessive NO_x emissions, depending on combustion conditions. It is technically feasible to reduce the nitrogen by hydrotreating, and , indeed, this would be necessary if the stock were to be further processed by catalytic cracking because of the catalyst poisoning effect of nitrogen compounds. It appears feasible, however, to use this material for boiler fuel by blending with a low nitrogen petroleum fuel oil.

Refining Cases

To illustrate the technology and economics of upgrading the coal syncrude to on-specification fuel products, four specific cases have been developed in detail. The major parameters of these cases are summarized in Table 15. As shown, the first two cases concern new, 100,000 barrel-per-stream-day refineries designed specifically for syncrude processing. Case 1 is a minimum cost refinery having no facilities for converting (cracking) the heavier fractions to lighter products. Case 2 represents a maximum jet fuel case in which all of the material heavier than kerosene

Table 15

SYNCRUDE REFINING CASES

	Case 1 New	Case 2 New	Case 3 Existing	Case 4 Existing
Feedstock (thousands of barrels per stream day)				
Syncrude	100.0	100.0		85
Sour crude			170	85
Production basis	No conversion	Maximum kerosene	Typical refinery	Limited by Case 4 cracking facilities

is converted to kerosene and lighter products by hydrocracking. The refining of syncrude in existing plants is evaluated in Cases 3 and 4, with Case 3 defining the crude only base case and Case 4 illustrating the requirements for processing a 50 percent syncrude feedstock. In the following discussion, each of these cases is examined in detail.

The gasoline in all cases is 91 research octane number (RON), unleaded, with a 9 to 10 psia Reid vapor pressure (RVP). The major quality specifications of the jet fuel correspond to the JP-8 grade, and all the jet fuel produced is of this kerosene type.

In Case 1, the minimum cost situation, the processing consists of a primary distillation step followed by hydrotreating of each fraction except the heavy fuel oil and catalytic reforming of the heavy naphtha fraction as shown in Figure 6. The butanes and lighter by-products of

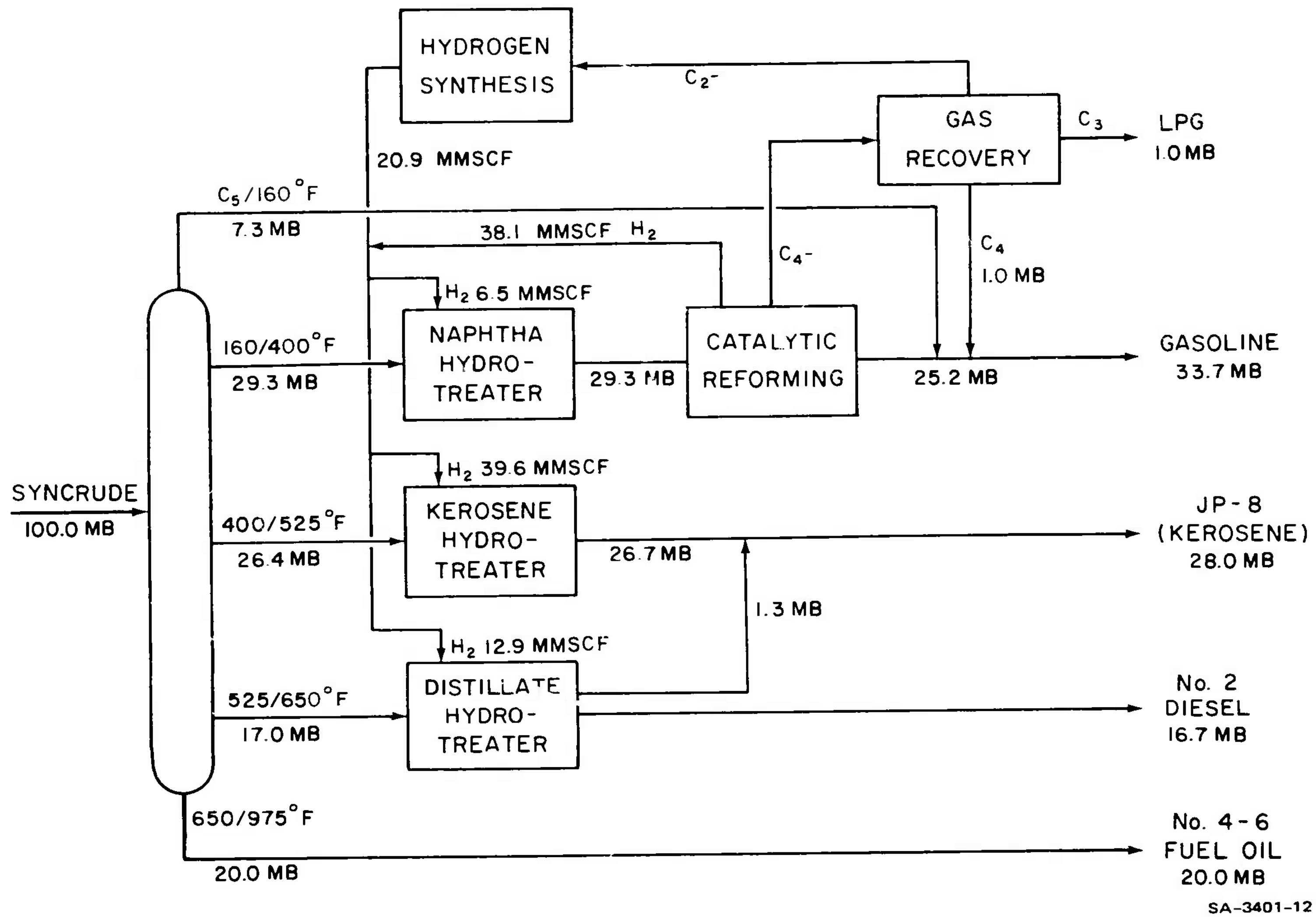

FIGURE 6 SYNCRUDE PROCESSING IN NEW REFINERY—MINIMUM COST SLATE (RATES IN UNITS PER STREAM DAY)

catalytic reforming are separated by conventional absorption and fractionation. Hydrogen of about 85 mol percent purity is produced in the catalytic reforming operation that may be used directly in the hydrotreating processes. The hydrogen requirements, however, are such that supplemental hydrogen must be produced by synthesis. In this case, the quantities of methane and ethane by-products of catalytic reforming are sufficient to supply feedstock for the supplemental hydrogen by the catalytic steam reforming process.

The hydrotreating processes for the naphtha and distillate fractions are similar in type, using single-stage, fixed-bed reactors with cobalt-molybdenum catalyst. In general, the operating severity of hydrotreating in terms of pressure and reactor space velocity increases as the molecular weight (or boiling range) of the feedstock increases.

For the additional aromatics saturation of the kerosene (jet fuel) fraction, a two-stage hydrogenation process is required. This entails a first stage of cobalt-molybdenum catalyst to remove sulfur, nitrogen, and oxygen, followed by a second stage with a noble metal catalyst in which the aromatics saturat[illegible] kes place. As indicated in Figure 6, the aromatics saturation operation consumes substantially more hydrogen per barrel of feedstock than the treatment to remove the hetero-atoms (S,O,N) in the naphtha and distillate hydrotreaters.

Catalytic reforming uses noble metal catalysts that require the prehydrotreating of the heavy naphtha (160° to 400°F) to remove the hetero-atoms that act as catalyst poison. The light naphtha (C_5-160°F) material is separated before reforming, since this boiling range contains very little of the naphthenic material that may be converted to aromatics in the reforming process. All these processes are well proved in commercial refinery applications. With the exception of two-stage kerosene hydrotreating, all the processes discussed in this section are standard components of a petroleum refinery, especially in those which process sour

(high sulfur) crude oil. Historically, two-stage hydrotreating of kerosene for jet fuel production has been applied in a relatively limited number of situations in whic · the crude oil being processed is unusually high in aromatic content.

The relative product volumes produced by this type of refinery are determined primarily by the feedstock distillation yields. In catalytic reforming, some hydrocracking occurs to convert 10 to 20 volume percent of the feed to C_4 and lighter materials. In low severity hydrotreating, the volume change is generally negligible, but in the more severe hydrotreating operation, such as that used for jet fuel production, some hydrocracking occurs that produces a slight volume increase in product over the feed volume.

Little flexibility exists in this type of refinery to increase the yield of jet fuel from the 28 percent to the proportion in excess of 60 percent required by the DoD. However, the demand for gasoline and fuel oils in the domestic and commercial sectors is strong, and it is likely that the DoD could trade these products on a barrel-for-barrel basis to achieve the desired product balance. Product trading is widely practiced among oil companies to correct regional marketing imbalances with the incentive of minimizing transportation costs.

New Maximum Jet Fuel Refinery

In Case 2 an additional process is included to produce lighter products more closely in line with the DoD demand pattern. As shown in Figure 7, hydrocracking is used to convert the 525° to 975°F fraction to kerosene and lighter products. The quality of the kerosene produced by hydrocracking generally exceeds the smoke point and freeze point specifications required for JP-8. The selectivity of the hydrocracking process, however, does not permit a total conversion of the heavier oils to kerosene. With existing hydrocracking technology, the maximum kerosene

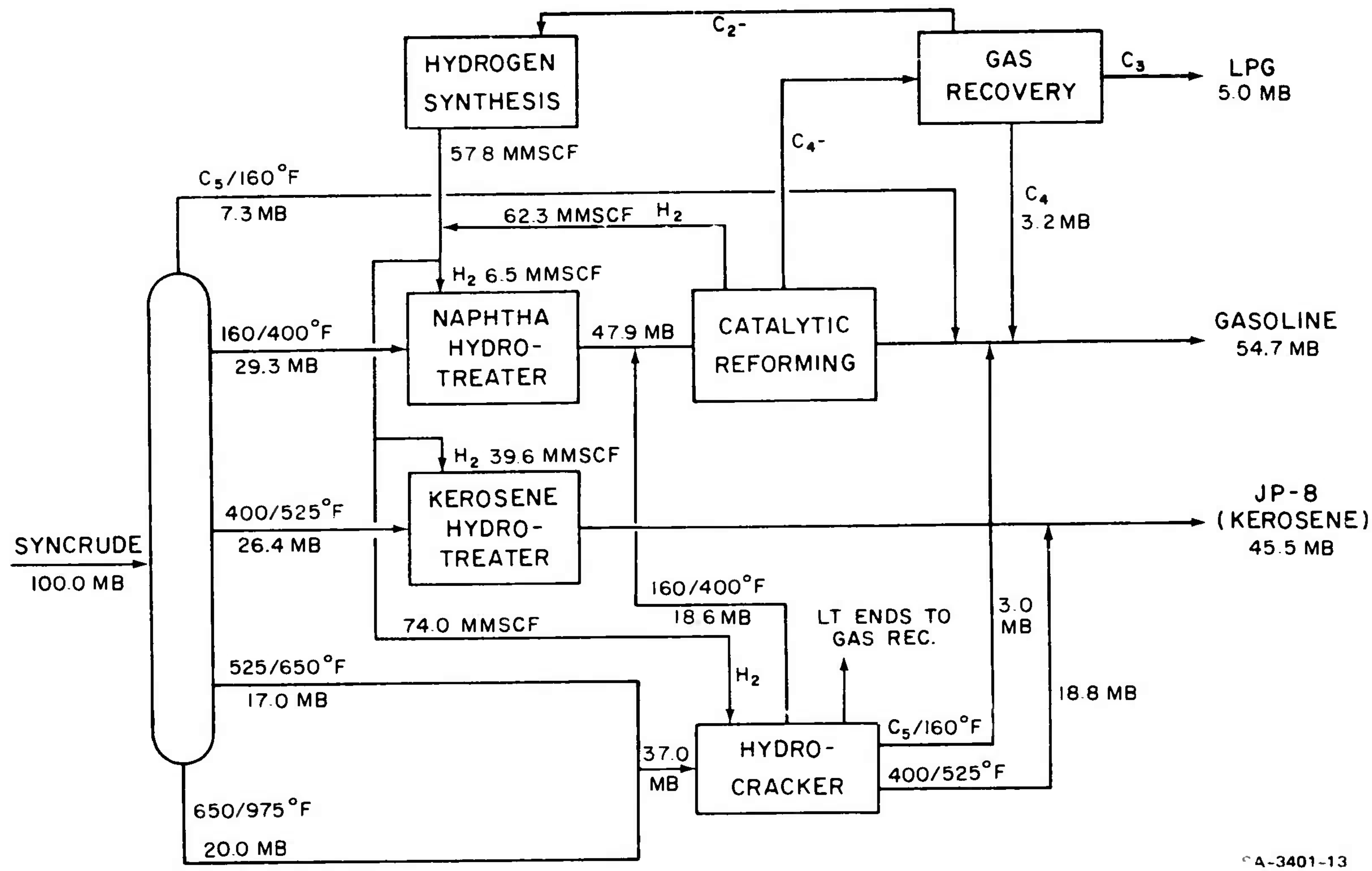

FIGURE 7 SYNCRUDE PROCESSING IN NEW REFINERY—MAXIMUM JET FUEL (RATES IN UNITS PER STREAM DAY)

operation will produce roughly equal quantities of kerosene and gasoline. It should be noted that this state of the art has developed in the environment of a high demand for gasoline. It is likely that higher kerosene selectivity could be achieved through process research in the area of catalyst modification along with optimization of the trade-offs of once-through conversion and recycle quantities. However, it does not appear probable that the magnitude of such improvements in kerosene selectivity would be sufficient to match the DoD requirement.

The major economic impacts of hydrocracking are the high investment and operating cost of the process, and the substantial consumption of hydrogen, which requires additional synthesis capacity and feedstock. Another significant effect is in the quality of the naphtha produced by hydrocracking in terms of gasoline octanes. Although the light fraction of hydrocracker naphtha is sufficiently high in octane to be blended directly to gasoline, the heavy fraction has an octane rating of less than 70 RON (unleaded), which requires that it be processed through catalytic reforming.

Existing Refinery

With existing U.S. refining capacity of more than 14 million barrels per day substantially exceeding the current domestic crude oil production of less than 9 million barrels per day (3 million barrels per day of foreign crude are imported), it is possible that future syncrude production could be refined in existing capacity rather than in new refineries. To evaluate this possibility, two cases were developed to define a typical refinery with only crude oil throughput (Case 3) and the modifications required to process a 50 percent mixture of crude oil and H-Coal syncrude (Case 4).

The definition of a typical refinery is a highly problematic exercise, since no two of the some 260 operating refineries in the United

States are exactly alike. Each of these refineries has been designed or has evolved to process certain feedstocks to produce certain products as determined by a particular company's feedstock position and marketing objectives. Thus, the analysis of these cases is intended to be illustrative of the advantages and disadvantages of including syncrude in the feedstock mix rather than to be definitive of industry-wide economics.

The general refinery configuration selected for this study is similar to the most recent completely new refinery built in the United States, the Mobil refinery in Joliet, Illinois, near Chicago. As shown in Figure 8, the base refinery in this study is a 170,000 barrel-per-day plant designed for processing a sour (i.e., high sulfur) west Texas crude. The part of the refinery concerned with processing the 650°F and lighter fraction of the crude is similar to the new refinery cases, with hydrotreating of each of the fractions from the atmospheric distillation unit and catalytic reforming of the 160° to 400°F naphtha for octane improvement. The kerosene hydrotreater in this case is a single-stage unit used primarily for sulfur reduction, as evidenced by the relatively low hydrogen consumption. Since this crude oil contains over 40 weight percent of atmospheric residuum (650°F+), a substantial part of the refinery processing is dedicated to upgrading this fraction.

Since the planning of this existing refinery would have been carried out in the environment of high-priced gasoline relative to residual fuel oil, the coking process was applied to minimize the production of residual fuel. In common with most U.S. refineries, fluid catalytic cracking (FCC) was applied to convert the vacuum gas oil (650° to 1000°F) to lighter products, gasoline in particular. Also in typical practice, the light olefin by-products of catalytic cracking, propylene and butylenes, are alkylated with isobutane to produce a high octane gasoline blending component. In the study case, each process is sized according to the feedstocks available from the crude and other processes. The resulting

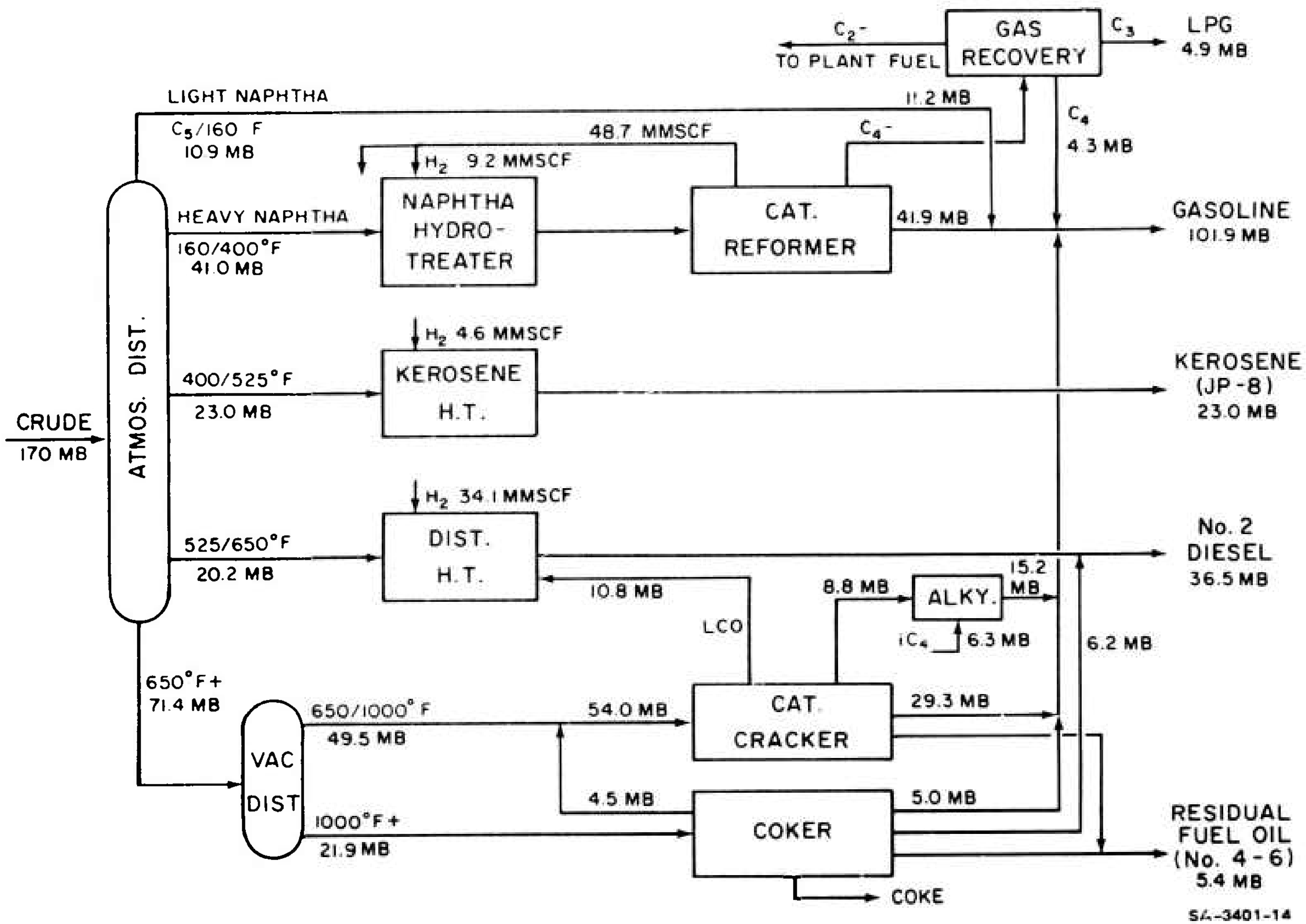

FIGURE 8 EXISTING REFINERY PROCESSING—CRUDE OIL ONLY (RATES IN UNITS PER STREAM DAY)

refinery thus produces about 60 percent gasoline, 13.5 percent jet grade kerosene, 21.5 percent No. 2 diesel, and the remainder a nominal amount of residual fuel oil and LPG. With the catalytic reformer running all of the straight-run heavy naphtha plus hydrotreated coker naphtha, the hydrogen by-product is roughly in balance with the requirements for hydrotreating.

Existing Refinery Modified for Syncrude

In replacing 50 percent of the crude oil feedstock to this refinery with H-Coal syncrude (Case 4), the major modification required is additional hydrotreating facilities and a hydrogen synthesis unit to supply the incremental hydrogen as shown in Figure 9. The major new hydrotreating unit is on the gas oil FCC feed stream. The FCC catalyst is highly sensitive to poisoning by the basic nitrogen compounds in the coal syncrude, which therefore must be removed by hydrotreating. The FCC feed hydrotreating unit is sized to treat the volume of vacuum gas oil from the crude as well as the syncrude, on the assumption that the syncrude is blended with the crude rather than being segregated and processed in blocked operation. This is considered justifiable since feed hydrotreating may be the most economical approach to controlling FCC sulfur emissions.

In addition to the FCC feed hydrotreater, the kerosene hydrotreater would acquire expansion to handle the additional volume of this fraction and modified by the addition of a second reactor stage. To provide the additional hydrogen requirement, a large (50.6 million scf per day) hydrogen synthesis unit would be required. The refinery fuel gas is estimated to be sufficient to support a steam reforming unit of this size, but this requires the purchase of additional process fuel to replace the gas. The FCC unit feed rate is maintained at full capacity by the diversion of a part of the 525° to 650°F stream from the No. 2 blending pool.

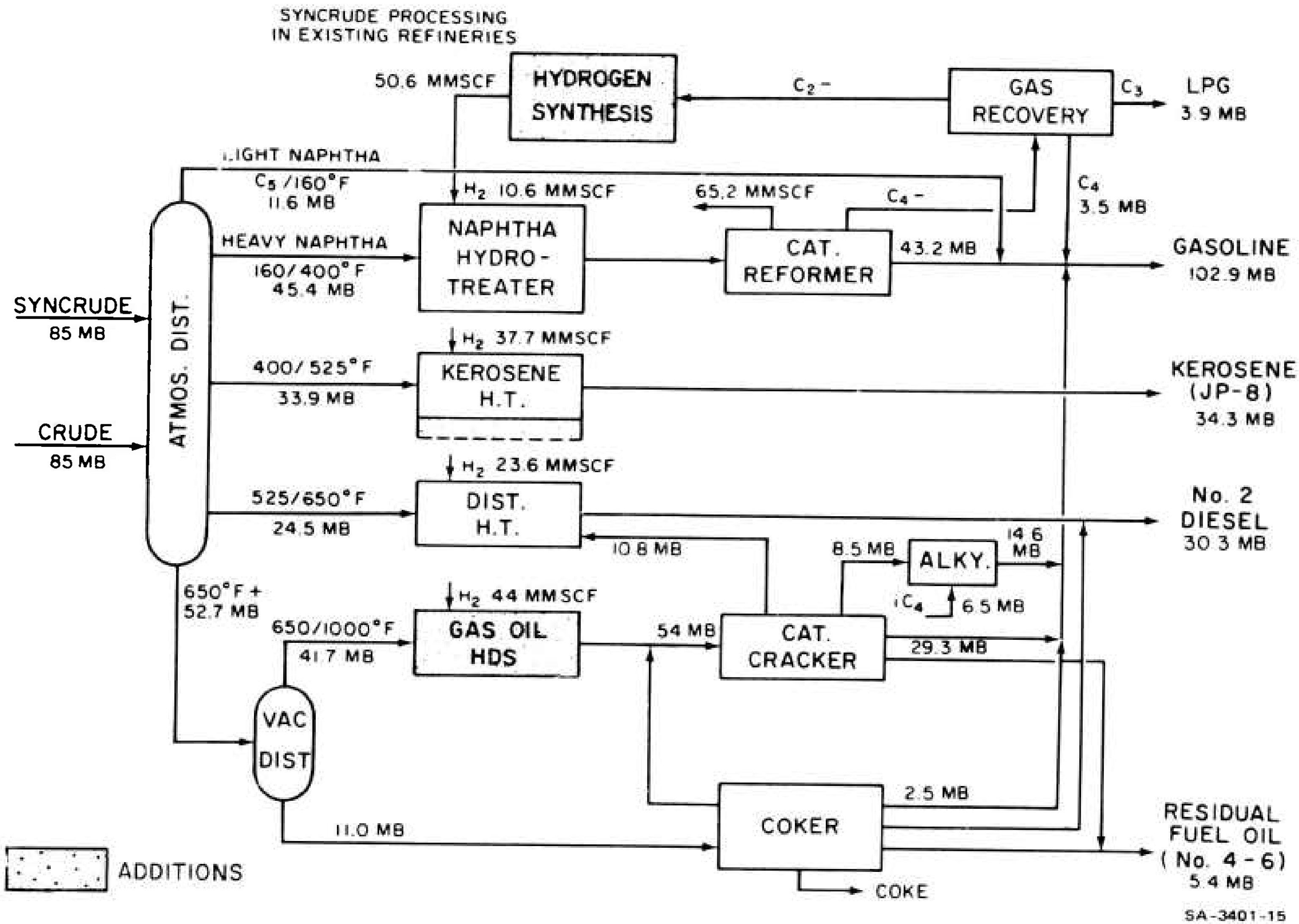

FIGURE 9 SYNCRUDE AND CRUDE PROCESSING IN MODIFIED REFINERY (RATES IN UNITS PER STREAM DAY)

The vacuum distillation unit throughput is substantially reduced because of the absence of 1000°F+ material in the syncrude. For this same reason, the coker throughput is reduced by half. Thus, the additional operating cost of the hydroprocessing facilities is partially offset by lower throughput in the residuum processing.

Integration of Syncrude Production with Existing Refineries

A cursory examination of the process flow diagrams of the coal conversion plant and the various refinery schemes reveals a number of similarities that suggest the possibility of process synergism in an integrated system. In addition, the well-publicized resistance to new plant siting by those concerned with environmental effects suggests that existing refinery sites could be preferable locations for new coal conversion facilities.

Some merit is likely for both these reasons to look at integrating the coal conversion with an existing refinery. However, in view of the wide diversity in site space availability, refinery equipment in place, and logistics support, it does not appear possible to quantify this possibility in a general sense.

From the standpoint of process integration, a major factor in the cost of coal liquefaction is the hydrogen consumption. While it is true that refineries that process low-sulfur crudes tend to produce excess hydrogen from their catalytic reforming operations, which is consumed as refinery fuel, it is also true that these refineries will not be equipped with the hydrotreating units needed for reduction of nitrogen and oxygen in the syncrude fractions. In the case of a sour crude refiner contemplating the possibility of adding new hydroprocessing facilities (such as FCC feed hydrotreating), the possibility of economies of scale may occur for common hydrogen generating facilities. However, the hydrogen requirement of a large coal conversion unit such as that evaluated in

this study corresponds to multiples of the largest single-train units of either partial oxidation or steam reforming units available. The economies of scale diminish substantially after the maximum single-train capacity is exceeded.

Another possibility for economy of scale is in the utilities area--the steam, cooling water, and possibly power generating and distribution facilities. This would require a case-by-case evaluation to assess excess capacity in existing facilities. It should be observed, however, that these facilities of the type used in refineries tend to be modular in sizes that generally require multiples in existing refineries, again diminishing any substantial cost reductions through scale.

Given that vacant space does exist at a given site, there are a number of items that could be utilized that tend to be fixed in cost and not directly related to plant throughput. Such items could be categorized as general site development, including fences, landscaping, plant security, access roads, fire protection, railroad spurs, maintenance shops, quality control laboratories, and administrative offices. In a typical installation, these items may amount to 10 to 15 percent of the total plant facilities investment.

The logistics question is likely to weigh on the negative side, since refinery sites tend to be pipeline oriented, rather than accessible to unit train railroad delivery of coal. Again, this question is extremely site specific.

Investment and Operating Costs for Syncrude Refining

The capital investment for a new refinery designed for refining the H-Coal syncrude is shown in Table 16. Two cases are shown: a minimum cost refinery without conversion facilities, and a refinery with conversion facilities to maximize the yield of jet fuel. The minimum cost

Table 16

CAPITAL INVESTMENT FOR NEW SYNCRUDE REFINERIES
(Basis: 100,000 Barrels per Stream Day)

	Millions of Dollars	
	Minimum Cost Refinery	Maximum Jet Fuel Refinery
Plant facilities		
Crude distillation	$ 9.8	$ 9.8
Naphtha hydrotreating	5.0	5.0
Kerosene hydrotreating	4.3	4.3
Distillate hydrotreating	3.1	--
Catalytic reforming	8.3	11.7
Hydrocracking		30.7
Hydrogen synthesis	5.2	10.1
Gas recovery	1.1	2.5
Sulfur recovery	0.8	1.0
Total onsite	$ 37.6	$ 75.0
Utilities, tankage, and other offsites	38.6	53.6
Total plant facilities	$ 76.2	$128.6
Working capital*	58.2	61.5
Other investment†	18.7	39.0
Total capital	$153.1	$229.0

*Includes syncrude at $10 per barrel.

†Includes land, royalties, interest during construction, start-up expenses, and initial inventories of catalysts and chemicals.

refinery produces a simple product slate and is lower in cost than typical modern crude refineries in the United States, which are designed to increase the gasoline yield by conversion of the heavy crude fractions.

The plant facilities include, in addition to the onsite facilities, utilities, tankage, and other off-site facilities. Working capital is required for the inventories of syncrude feedstock, intermediate streams, and products. Interest paid during construction is a substantial part of investment. Other investment also includes land, royalties, start-up expenses, and initial inventories of catalysts and chemicals.

The principal added cost for maximizing jet fuel is for the hydrocracking facilities. The costs of the catalytic reforming, hydrogen synthesis, and off-site facilities are increased. The higher facilities' costs increase the interest during construction.

Table 17 shows the capital investment for a typical modern refinery and the costs of modifying that refinery to accept 50 percent syncrude in the input stream. The major modification costs are for the addition of a gas oil hydrotreater and hydrogen synthesis facilities. The total incremental cost for modifying the refinery is only 10 percent of the original refinery capital investment.

The annual operating costs, excluding syncrude, for the new syncrude refineries are shown in Table 18. Two-thirds of the operating costs, excluding feedstock, are for plant fuel, assuming a price of $10 per barrel. Plant fuel costs for the maximum jet fuel case are twice as much as for the minimum cost refinery; and the total operating costs, excluding feedstock, are also twice as much. These operating costs for the minimum cost refinery are substantially less than is typical for modern U.S. refineries, while the operating costs for the maximum jet fuel case are more comparable with those of existing refineries.

Table 17

CAPITAL INVESTMENT FOR MODIFICATION
OF EXISTING REFINERY TO REFINE SYNCRUDE
(Basis: 170,000 Barrels per Stream Day)

	Millions of Dollars	
	Existing Refinery	Incremental Cost to Modify for 50% Syncrude
Plant facilities		
Crude distillation	$ 13.9	
Vacuum distillation	5.4	
Fluid catalytic cracker (FCC)	28.3	
Coker	13.9	
Naphtha hydrotreater	6.7	
Kerosene hydrotreater	3.9	$ 1.3
Distillate hydrotreater	5.4	
Gas oil hydrotreater	--	10.7
Catalytic reformer	11.8	
Alkylation	8.8	
Hydrogen synthesis	--	9.2
Gas recovery	4.5	
Sulfur recovery	4.9	
Total onsite	$107.6	$21.2
Utilities, tankage, and other offsites	80.8	5.2
Total plant facilities	$188.3	$26.4
Working capital*	104.3	1.5
Other Investment†	46.0	6.1
Total	$338.6	$34.0

*Includes feedstock at $10 per barrel.

†Includes land, royalties, interest during construction, start-up expenses, and initial inventories of catalysts and chemicals.

Table 18

ANNUAL OPERATING COSTS FOR REFINING
SYNCRUDE IN NEW REFINERIES
(Basis: 100,000 Barrels per Stream Day)

	Millions of Dollars	
	Minimum Cost Refinery	Maximum Jet Fuel Refinery
Labor		
Operating labor and supervision	\$ 0.71	\$ 0.78
Maintenance labor	0.75	1.50
Payroll burden and G&A overhead	0.83	1.28
Total labor	\$ 2.30	\$ 3.56
Materials and supplies (excluding syncrude)		
Plant fuel at \$10/barrel	15.00	30.48
Other materials	2.21	4.33
Total materials and supplies	\$17.21	\$34.81
Electric power at 1.25¢/kWh	0.96	2.53
Fixed costs		
Plant overhead	1.52	2.57
Property taxes and insurance	1.52	2.57
Total fixed costs	\$ 3.05	\$ 5.14
Total operating costs (excluding syncrude)	\$23.52	\$46.04

The annual operating costs, excluding feedstock, for a typical modern U.S. refinery, and for a modification of that refinery to process 50 percent syncrude, are shown in Table 19. The plant fuels and isobutane are the largest element of the operating costs, and the increase in plant fuel cost for the modified refinery is the major part of the increase in operating costs.

The total syncrude refining costs, including investment costs and federal income tax, are given in Section VII.

Table 19

ANNUAL OPERATING COSTS FOR REFINING CRUDE AND SYNCRUDE IN MODIFIED REFINERY
(Basis: 170,000 Barrels per Stream Day)

	Millions of Dollars	
	Existing Refinery, Crude Only	Modified Refinery, 50% Crude, 50% Syncrude
Labor		
Operating labor and supervision	$ 1.22	$ 1.42
Maintenance labor	2.15	2.37
Payroll burden and G&A overhead	1.88	2.12
Total labor	$ 5.25	$ 5.91
Materials and supplies (excluding feedstock)		
Isobutane at $9 per barrel	18.99	19.50
Plant fuel at $10 per barrel	32.90	39.70
Other materials	5.89	6.87
Total materials and supplies	$57.78	$66.07
Electric power at 1.25 cents per kWh	5.09	5.24
Fixed costs		
Plant overhead	3.77	4.36
Property taxes and insurance	4.71	5.45
Total fixed costs	$ 8.48	$ 9.81
Total operating costs (excluding feedstock)	$76.60	$87.03

VI PLANT LOCATION CONSIDERATIONS

Coal Resources

The total of identified and hypothetical U.S. coal resources up to depths of 3,000 feet is 2,887 billion tons, as shown in Table 20.[9] Over half of this total is identified resources. Of the identified resources, 400 billion tons are in thick beds less than 1,000 feet in depth, a thickness and overburden category comparable with coal now being mined and therefore of current economic interest. Another 350 billion tons are in beds of intermediate thickness, less than 1,000 feet in depth. Some coal in this thickness and overburden category is currently being mined, and this category can be considered a marginal resource that will become of increasing economic interest in the future.

Remaining strippable resources (not necessarily economical to mine) total 118 billion tons. Of that total, strippable reserves (available with existing technology) are 45 billion tons.

The usual recovery of coal in underground mining is about 50 percent, although higher recovery rates are possible with the longwall mining technique. Strip mining recovery rates are above 80 percent except in hilly terrain.

The National Petroleum Council[10] (NPC) estimated economically recoverable reserves of coal to be 105 billion tons of underground minable

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[9] Paul Averitt, "Coal," U.S. Geological Survey Paper 820, U.S. Mineral Resources, Department of the Interior (1973).

[10] "U.S. Energy Outlook," National Petroleum Council (1972).

Table 20

COAL RESOURCES OF THE UNITED STATES[9]
(Billions of Tons)

Identified resources 0-3,000 feet	1,581
Thick beds, 0-1,000 feet	(400)
Intermediate thickness beds, 0-1,000 feet	(350)
Hypothetical resources, 0-3,000 feet	1,306
Total resources 0-3,000 feet	2,887
Stripping resources	118
Economically strippable reserves	45

[9] Paul Averitt, "Coal," U.S. Geological Survey Paper 820, U.S. Mineral Resources, Department of the Interior (1973).

coal and 45 billion tons of surface minable coal. Both figures refer to the amount that would be produced, taking account of the respective recovery rates. The NPC figure for underground minable coal reflects coal prices at the time of the report (1972) and excludes most of the western underground minable coal resources.

The present U.S. production of coal is approximately 0.6 billion tons per year. The National Academy of Engineering[11] estimated a capability for expanding coal production to 1.3 billion tons per year by 1985. A plant producing 100,000 barrels per day of syncrude from coal, with a nominal three barrels-per-ton of coal, and a 30-year plant life, would require recoverable reserves of approximately 0.3 billion tons of coal.

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[11] "U.S. Energy Prospects: An Engineering Viewpoint," National Academy of Engineering (1974).

Location of Coal Resources

The location of U.S. coal fields is shown in Figure 10. The amounts of identified resources and strippable reserves in three areas, (1) Eastern Province (Appalachian), (2) Interior Province (Midwest), and (3) Rocky Mountain and Northern Great Plains Provinces (Western), are given in Table 21. The greatest resources as well as the largest strippable reserves are in the western states. North Dakota has the largest identified resources at depths of less than 3,000 feet--351 billion tons--but of the low-heat value lignite. Other states with identified resources at depths less than 3,000 feet, or more than 100 billion tons, are Alaska, Illinois, Montana, West Virginia, and Wyoming. The NPC figure for underground recoverable reserves in Illinois and Indiana is 29.7 billion tons.

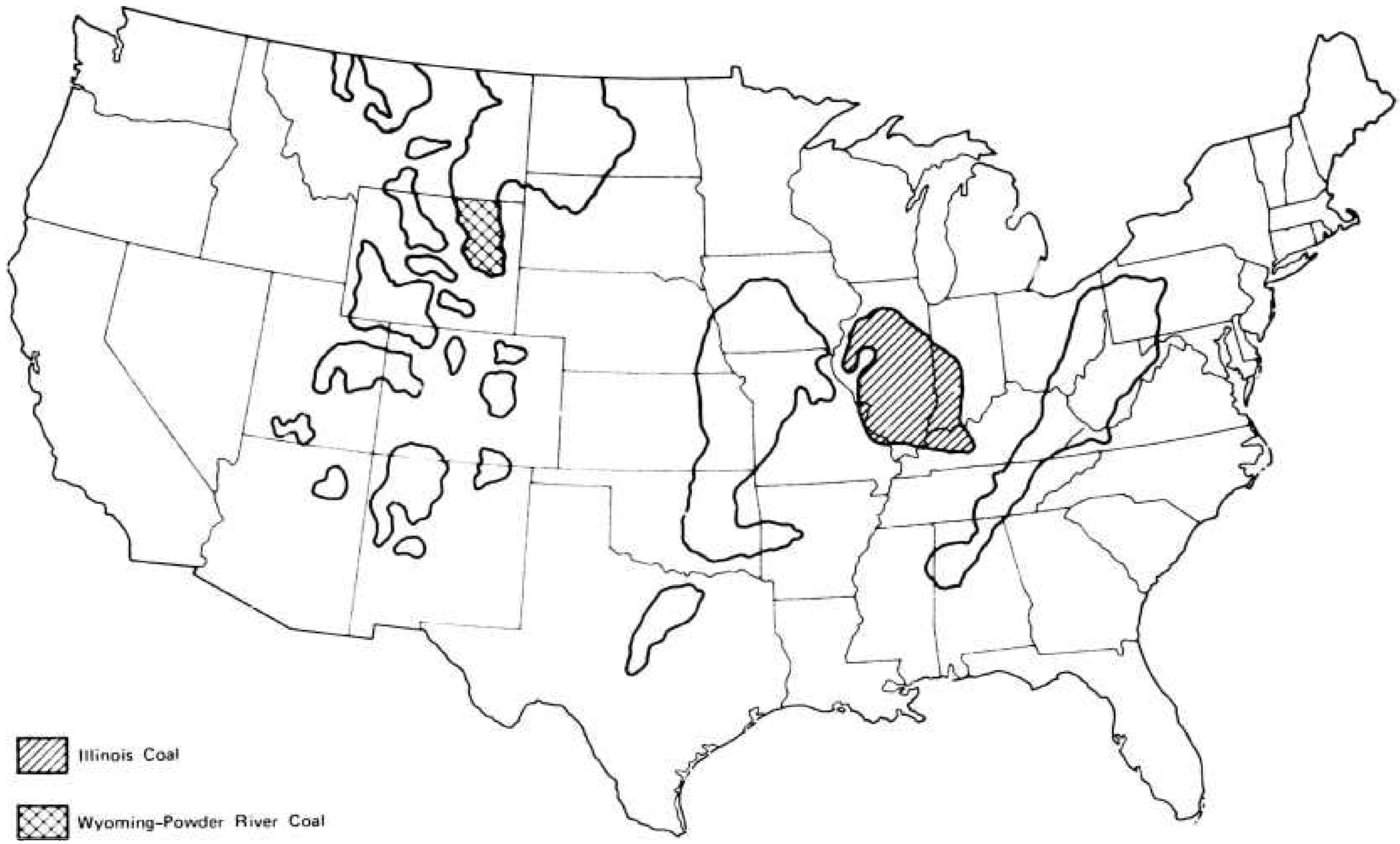
Table 21

LOCATION OF U.S. COAL RESOURCES[9,12]

Location	Identified Resources 0-3,000 ft	Economically Strippable Reserves
Eastern	239	4
Interior	323	10
Rocky Mountain and Northern Great Plains	882	27
Total	1,444	41

[9] Paul Averitt, "Coal," U.S. Geological Survey Paper 820, U.S. Mineral Resources, Department of the Interior (1973).

[12] "Strippable Reserves of Bituminous Coal and Lignite in the United States, Bureau of Mines Information Circular 8531 (1971).



SOURCE: Adapted from U.S.G.S. Coal Map of the U.S., 1960.

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FIGURE 10 COAL FIELD OF THE UNITED STATES

Strippable reserves in the Midwest are primarily in Illinois (3.2 billion tons), Indiana, Western Kentucky, and Missouri. Wyoming has the largest strippable reserves--14 billion tons--with most of this along the Powder River in Northwestern Wyoming. Montana and New Mexico also have 3.4 and 2.5 billion tons, respectively, of subbituminous strippable reserves.

The western coal fields, in addition to the drawback of greater distances from major markets than the eastern and midwestern coal fields, are in an arid region with limited water supplies. Low precipitation makes rehabilitation of strip mined lands more difficult. Although water requirements for coal mining itself are not great, the limited water supplies will be a constraint on synthetic fuel plants and other industrial or electric power generation developments.

In the Southwest, most of the coal fields are located on the Colorado Plateau, which is more arid than the northern Great Plains and lies within the drainage of the Colorado River and its tributaries. Use of the streamflow in the Upper Colorado River Basin is largely committed. Hence, water supplies would severely constrain production of synthetic fuel from coal in this area. The development of the shale oil resources in that area would further compete for the limited supply of water.

The coal fields of northeastern Wyoming and southeastern Montana are in the area of the Yellowstone subbasin. The major rivers include the Yellowstone, Bighorn, Powder, and Tongue and their tributaries. Water supplies are not as committed as in the Colorado River Basin, and with water development projects, substantial supplies (e.g., 2.6 million acre-feet per year[13]) could be made available for mines and energy conversion

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[13] "Montana-Wyoming Aqueduct Study," Bureau of Reclamation, Department of the Interior (1972).

facilities. However, Montana has imposed a three-year moratorium on water allocations out of the Yellowstone River Basin.

Coal Types

The identified resources of each of the three types of coal (excluding the much smaller resources of anthracite reserved principally for steel-making) are shown in the following tabulation:[9]

Coal Type	Identified Resources, 0-3,000 ft (billions of tons)
Bituminous	686
Subbituminous	424
Lignite	450

The Appalachian and Midwestern coal resources are principally bituminous. The western coal (Rocky Mountain and Northern Great Plains) is principally subbituminous, except for 82 percent bituminous in Colorado and lignite in North Dakota and eastern Montana.

The coal resources vary in heat value and sulfur content. Typical heat values of the three types of coal in millions of Btu per ton are:

Bituminous	
Appalachian	27
Interior and Rockies	24
Subbituminous	19
Lignite	13

[9] Paul Averitt, "Coal," U.S. Geological Survey Paper 820, U.S. Mineral Resources, Department of the Interior (1973).

Thus, the western coals are generally much lower in heat value than the eastern and midwest coals.

The sulfur content of coal is significant because of the sulfur oxide emissions from combustion of fuels containing sulfur. The Clean Air Act limits sulfur oxide emissions to 1.2 pounds per million Btu of heat generated. On this basis, a coal with a heat value of 24 million Btu per ton cannot contain more than 0.7 percent sulfur and still meet the standard.

Most of the eastern and midwestern coal is much higher than that in sulfur content, while the western coals are predominantly low sulfur. However, correcting the sulfur content of the western coal to account for the lower heat value, results in an 85 percent reduction in the reserves of western coal in the less than 0.7 percent sulfur category.[14] However, the western coal remains generally lower in effective sulfur content than the eastern and midwestern coals.

Coal liquefaction permits removal of most of the sulfur. Hence, the syncrude plants can utilize high-sulfur coal. The National Petroleum Council[10] expects that most synthetic fuels plants will be build in the west to take advantage of the large strippable reserves. However, it might be preferable to reserve the low-sulfur western strippable coal for electric power generation.

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[14] Michael Rieber, "Low-Sulfur Coal: A Revision of Reserve and Supply Estimates," Center for Advanced Computation, University of Illinois (November 30, 1973).

[10] "U.S. Energy Outlook," National Petroleum Council (1972).

Refineries

U.S. refineries are heavily concentrated along the Gulf Coast. Additional smaller concentrations are in eastern Kansas and Oklahoma, the Midwest, the New Jersey and Philadelphia areas, and California. Figure 11 illustrates the refinery locations. The lengths of the bars indicate relative capacity, and many of the bars refer to several refineries in the same vicinity.

The midwestern refineries are near the large Illinois coal deposits. The refineries in eastern Kansas and Oklahome are near the smaller coal deposits of those states. There is little refinery capacity near the important Powder River coal fields in northwestern Wyoming.

The following tabulation gives present and projected U.S. refinery capacity (in thousands of barrels per day):[15]

1973	13,835
1974	14,518
1975	15,283
1976	16,341
1977	17,887

Corresponding crude runs in 1973 were 12,431, or 90 percent of capacity. Most of the current capacity gains are the result of expansions of existing plants. Not until 1977 will a large part of the increase consist of new plants.

U.S. crude production was 9.2 million barrels per day in 1973. Production, which peaked in November 1970, may be in a declining trend, although the potential for expansion of crude production in response to the

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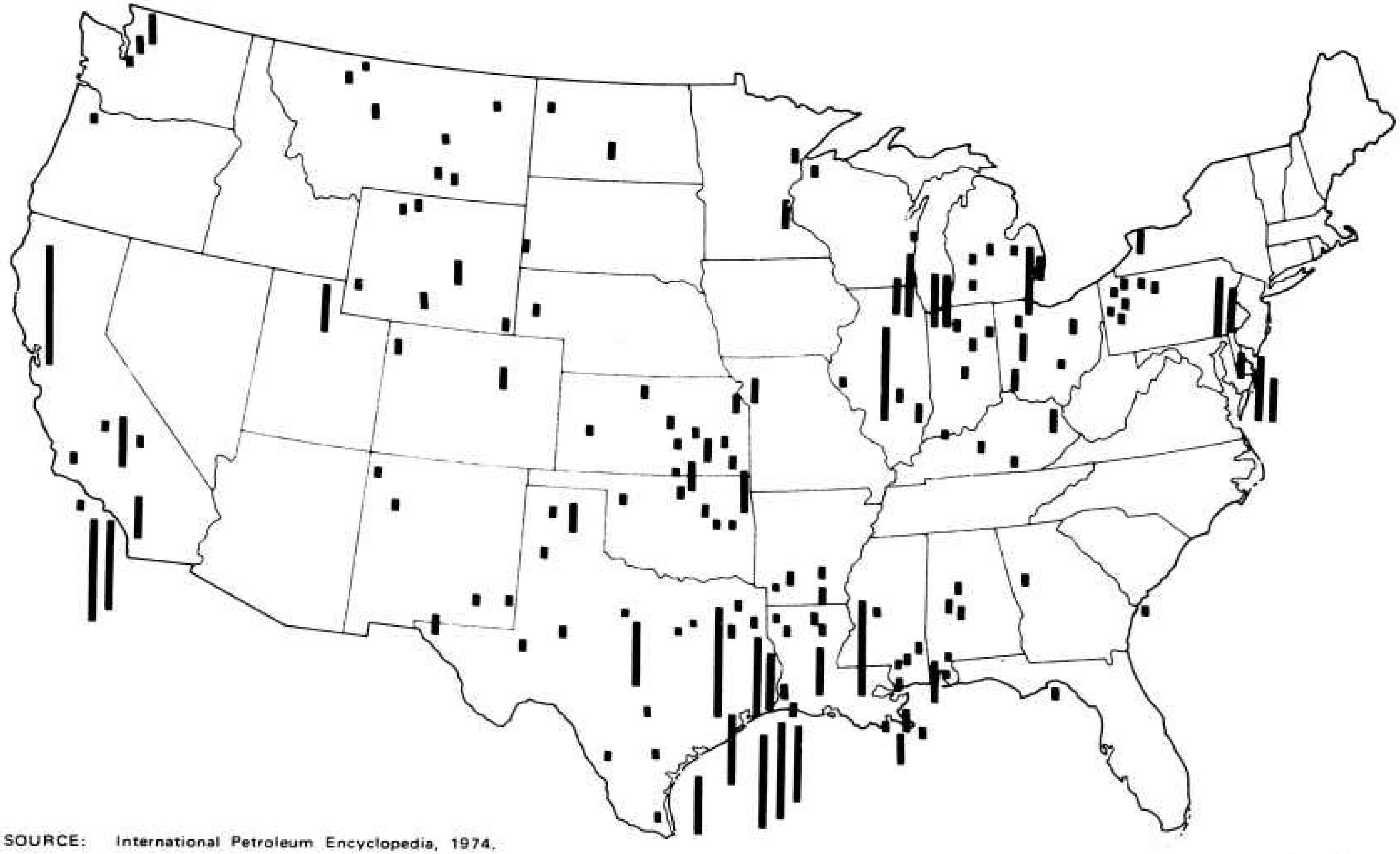
[15] "Trends in Refinery Capacity and Utilization," Federal Energy Office (June 1974).



SOURCE: International Petroleum Encyclopedia, 1974.

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FIGURE 11 U.S. REFINERY LOCATIONS

higher prices is controversial. Thus, refinery capacity substantially exceeds domestic crude production. If the goals of Project Independence are achieved and crude imports are greatly reduced, there might be excess refinery capacity which could then be used for refining syncrude.

Syncrude Plant Locations

Considerations in selection of locations for syncrude plants for DoD supply include the locations of coal fields, refineries, and pipelines, the availability of water, and the geographic areas of consumption. These considerations are discussed in terms of two example locations corresponding to the selected eastern and western coals, i.e., Illinois and the Powder River Basin in northeastern Wyoming. Transportation costs are discussed in Section VIII.

Powder River Basin

As previously mentioned, this area has large reserves of strippable low-sulfur coal, which can be mined at relatively low cost. There is little refinery capacity in or near the area. Crude pipelines run to eastern Kansas and Oklahoma, where substantial refinery capacity exists. There are no product pipelines. The distance to the Chicago area, if the coal is shipped to the Midwest by train, is 1,100 miles. Transportation costs would then make the coal higher in cost than underground mined midwestern coal. Alternatively, the coal could be shipped 200 miles to the Missouri River in South Dakota and then by barge down the river or converted to syncrude in a plant along the river. As discussed in Section X, a 100,000 barrel-per-day syncrude plant would consume 28,000 acre-feet-per-year of water. With present water availability of only 120,000 acre-feet per year for industrial development in Wyoming, it would be possible to have, say, three syncrude plants for DoD supply; however,

that would use up most of the available water. The area is also remote from the major areas of DoD petroleum product consumption.

These considerations suggest that use of coal from this area for DoD syncrude supply may be less desirable than use of midwestern coal. If the Powder River coal is used, its use might be limited to a single 100,000 barrel-per-day plant, with the syncrude shipped by pipeline to eastern Kansas or Oklahoma for refining.

Illinois

Illinois, with 3.2 billion tons of strippable reserves and much larger underground recoverable reserves, is a major candidate for syncrude plants. Refinery capacity in Illinois is about one million barrels per calendar day. Product pipelines pass through Illinois extending northwest to Lake Michigan and Lake Erie. The Mississippi River to the west and the Ohio River to the south provide potential routes for barge transportation of the coal, syncrude, or products.

VII ECONOMIC ANALYSIS

Economic Bases

Economic bases used in the study for investment analysis and operating costs are summarized in Table 22. Unless otherwise noted, all costs are expressed in constant 1974 U.S. dollars.

Two different assumptions were followed regarding investment capitalization and profitability analysis for determining the required project revenue and product values. In one approach, it was assumed that the entire capital requirements would be provided from equity investment, and product prices were then fixed to yield either a 10 or a 15 percent per year discounted cash flow (DCF) rate of return on total capital after taxes. The second approach assumed a regulated utility type of operation with a 65/35 debt to equity ratio, and product prices were set to cover 10 percent interest on debt and yield 15 percent return on equity investment. For comparison, costs are also given as though the plant were a DoD facility, with the initial costs converted to uniform annual costs using a 6-1/8 percent discount rate.

Investment Bases

Plant facilities investment (PFI) is the total erected cost of the coal conversion plant and refinery ready for start-up, including all contractors' direct and indirect costs. The PFI does not include allowances for contingencies, construction productivity changes, or the effects of future inflation.

Table 22

ECONOMIC BASES

Plant Investment Factors

Value of dollar--January 1974.
Nelson refinery construction index--470.
Plant facilities investment (PFI)--total installed cost of all process facilities, utilities, and off-sites required by the plant; includes contractors fee, and direct and indirect costs but not contingencies.

Plant capitalization and profitability analysis

Case	Source of Capital (percent)		Plant Tax Life (years)	Depreciation Schedule	Revenue Set to Yield (percent)	
	Debt	Equity			Interest on Debt	Return on Equity
Industrial	0%	100%	15	SOYD*	--%	15%
Industrial	0	100	15	SOYD*	--	10
Regulated utility	65	35	30	SL†	10	15
DoD costing	100	0	25	--	6.125	--

Organization and start-up expenses (percent of PFI)	6%
Paid-up royalty (percent of PFI)	3%
Working capital	
Coal feed to conversion plant (days)	14
Crude and syncrude feed for refinery (days)	30
Refinery products inventory (days)	30
Labor (months)	3
All other cash expenses	1
Land cost (dollars per acre)	
Plant construction schedule (percent of PFI)	
First year	20%
Second year	60
Third year	20

Plant Operating Factors

Plant production during first year of start-up--50% of on-stream factor		
Plant on-stream factor		
Percent of year		90%
Days per year		328.5
Labor factors		
Operating labor (OL)		
Dollars per hour		5.75
Dollars per man-shift year		$50,370
Supervisor (percent of OL)		15%
Maintenance labor (ML) (percent of PFI)		1-3%
G and A overhead labor (percent of OL + ML)		20%
Payroll burden (percent of OL + ML + GA)		30%
	Base case	**Range**
Raw material costs (dollars per ton at plant)		
Illinois No. 6 coal	9	7-15
Wyoming Powder River coal	3	2-5
Chemicals and catalysts--1974 market values		
Utilities--electric power (dollars per kilowatt hour)‡		$0.0125
Fixed costs (percent of PFI)		
Plant overhead		2%
Property insurance and local taxes		2%

*Sum of years digits.

†SL = straight line.

‡Cooling water, boiler feed water, and waste water treatment is included in utilities investment and operating costs

It is assumed that coal is purchased delivered to the plant, and consequently, the mine investment and coal transportation facilities are not included in the capital requirements. Similarly, it is assumed that syncrude and refined products would be transported via common carrier pipelines (or trains); therefore, the investment in product transportation facilities is not included.

Organization and Start-up Costs

These costs include crew training during start-up, plant owners' supervision during construction, and losses in raw materials and operating labor during start-up.

Working Capital

Working capital is required to meet cash expenses for labor, materials, and utilities until receipt of accounts receivable.

Land Cost

A cost of $5,000 per acre includes rough grading and site preparation.

Paid-up Royalty

Three percent of the plant facilities cost is assumed as payment for proprietary processes used in the coal conversion plant or refinery.

Plant Construction Period and Life

It was assumed that three years would be required for construction and that the plants would be depreciated over a 15-year period for the industrial cases and 30 years for the utility-type finance case.

Operating Cost Bases

The conversion plant and refinery were assumed to operate at a 90 percent plant factor, or 328.5 days per year.

Base prices of coal purchased for the coal conversion plants are given in Table 22 along with a range of coal prices used to determine the sensitivity of syncrude cost to coal price.

By-product credits were taken for the ammonia and sulfur produced in the coal conversion processes. A computer program was used to calculate the prices required to meet expenses and yield the selected return on investment.

Coal Mining Costs

The cost of mining coal in the United States varies widely with local geological conditions and regional economic factors. The coal costs used in the study were developed for average mining conditions in the selected areas and as a result represent average coal costs. The effects on syncrude cost of variation in coal costs were also studied for both ideal and severe mining conditions.

Cost of coal from underground mines depends largely on the following factors:

- Coal seam thickness--halving the seam thickness sometimes more than doubles the cost per ton because of reduced productivity and higher operating costs.
- Mining conditions--costs will be higher in mines with faulted seams, excessive gas, or poor roof and drainage conditions.
- Type of equipment used in the mine (conventional, continuous, or longwall) and the methods of coal handling underground and transportation to the surface.
- Human factors, including skill and training of miners and effectiveness of supervision and management.

Sources of major coal cost variations in surface mines are as follows:

- The ratio of overburden to coal seam thickness (stripping ratio).
- The type of overburden--loose unconsolidated overburden can be stripped without drilling and blasting, but overburden containing rocks or consolidated strata must be broken up before stripping.
- Seam faults and inclusions of shale or clay in the coal seam whose presence will increase the cost of selectively removing the coal.
- Transportation conditions and distances in and near the mine.
- Surface terrain and mine drainage conditions.
- Mine size and type of mining equipment used for overburden stripping and coal removal.

More favorable or ideal mining conditions could reduce the underground eastern coal cost by an estimated $1.00 to $1.50 per ton. Similarly, a more favorable stripping ratio of 1/1 would reduce the western surface mine costs by $0.40 per ton. On the other hand, more severe underground mining conditions such as thinner seams could increase the eastern coal cost by $2 to $6 per ton. Increasing the stripping ratio to 10/1 in surface mines would increase the cost of western coal by $1 to $3 per ton. The effect of mining conditions on mine-mouth coal cost in dollars per ton are shown below:

	Ideal Mining Conditions	Average Mining Conditions	Severe Mining Conditions
Eastern underground mine	$7.5-8	$9	$11-20
Western surface mine	2	3	4-6

While it is difficult to predict future coal costs, it appears that coal costs may escalate even more rapidly than the general economy and in the short run approach some percentage of oil prices, such as 70 percent,

which reflects lower demand and relative unattractiveness of coal compared with liquid fuels. Based on an oil price of $10 per barrel (1.72 per million Btu), coal costs might increase to $29 per ton ($1.20 per million Btu). Indicative of this trend is a recent TVA contract for bituminous coal for $30 per ton delivered to the plant over a two-year period. However, in the long run, coal prices should reflect mining costs such as indicated in Table 23.

Table 23

COAL MINING COSTS
(Dollars per Ton)

	Illinois No. 6 Bituminous Coal--Underground Mining	Wyoming Powder River Subbituminous Coal--Surface Mining
Operating costs		
Labor	$ 3.20	$0.90
Mine supplies	1.49	0.50
Utilities	0.15	0.08
Royalties	0.30	0.20
Taxes and insurance	0.12	0.08
Total operating costs	$ 5.26	$1.76
Depreciation	0.98	0.32
Depletion allowance	0.90	0.30
Net income	0.91	0.31
State and Federal income tax	0.95	0.31
Total coal cost	$ 9.00	$3.00
Mine investment ($/annual ton)	$19.60	$6.50

Factors indicating future increases in coal costs are:

- Labor costs are expected to rise significantly starting in 1974. The union is reportedly seeking a 50 percent increase, which would add about $1.50 per ton to eastern coal costs.
- Equipment costs have escalated and are expected to continue. Supply costs are higher, particularly for steel roof bolts used extensively in underground mining.
- Many of the more attractive eastern coal deposits have already been worked out.
- The availability of debt capital will be low and returns necessary to attract equity capital will be higher.
- Royalty payments to the resource owner will increase.
- Costs for health, safety, and environmental controls will be higher.
- Energy costs for electricity, diesel fuel, gasoline, and so forth will increase.

Total Cost of H-Coal Syncrude

The estimated investment and operating costs of H-coal syncrude were given in Section IV. This discussion develops the total costs of the syncrude for different methods of financing.

Table 24 gives the annual costs and costs per barrel of syncrude from Illinois No. 6 coal, with underground mined coal at a price of $9 per ton. Figure 12 illustrates the cost elements per barrel of syncrude.

The net operating cost is the sum of the coal cost and operating cost less credit for the by-products. In the costs associated with the capital investment and taxes, for an industrial-type financing case, is included depreciation, an after-tax return on investment of 15 percent discounted cash flow (DCF), and federal income tax based on a 50 percent rate. The 15 percent DCF is typical of the return that would be expected for a venture in a relatively new area entailing some risk. The same costs are also given for a 10 percent DCF, which might be adequate if the risk

Table 24

TOTAL COSTS FOR H-COAL SYNCRUDE FROM ILLINOIS NO. 6 COAL
(Basis: 100,000 B/SD)

	Annual Costs (millions of dollars)		Cost per Barrel (dollars)
Coal cost at $9/ton		$112.88	$ 3.43
Operating cost (excluding coal)		74.99	2.28
Credit for by-products			
Ammonia at $100/ton	$13.70		
Sulfur at $25/ton	7.58		
Total credit		(21.28)	(0.65)
Net operating cost		$166.59	$ 5.06
Industrial--15 percent DCF			
Depreciation and net income (average)			3.81
Federal income tax (average)			2.51
Required syncrude revenue		374	$11.38
Industrial--10 percent DCF			
Depreciation and net income (average)			2.79
Federal income tax (average			1.49
Required syncrude revenue		307	9.34
Utility financing			
Interest, depreciation and net income (average)			2.57
Federal income tax (average)			.55
Required syncrude revenue		249	8.18
DoD costing			
Investment cost			1.65
Required syncrude revenue		220	6.71

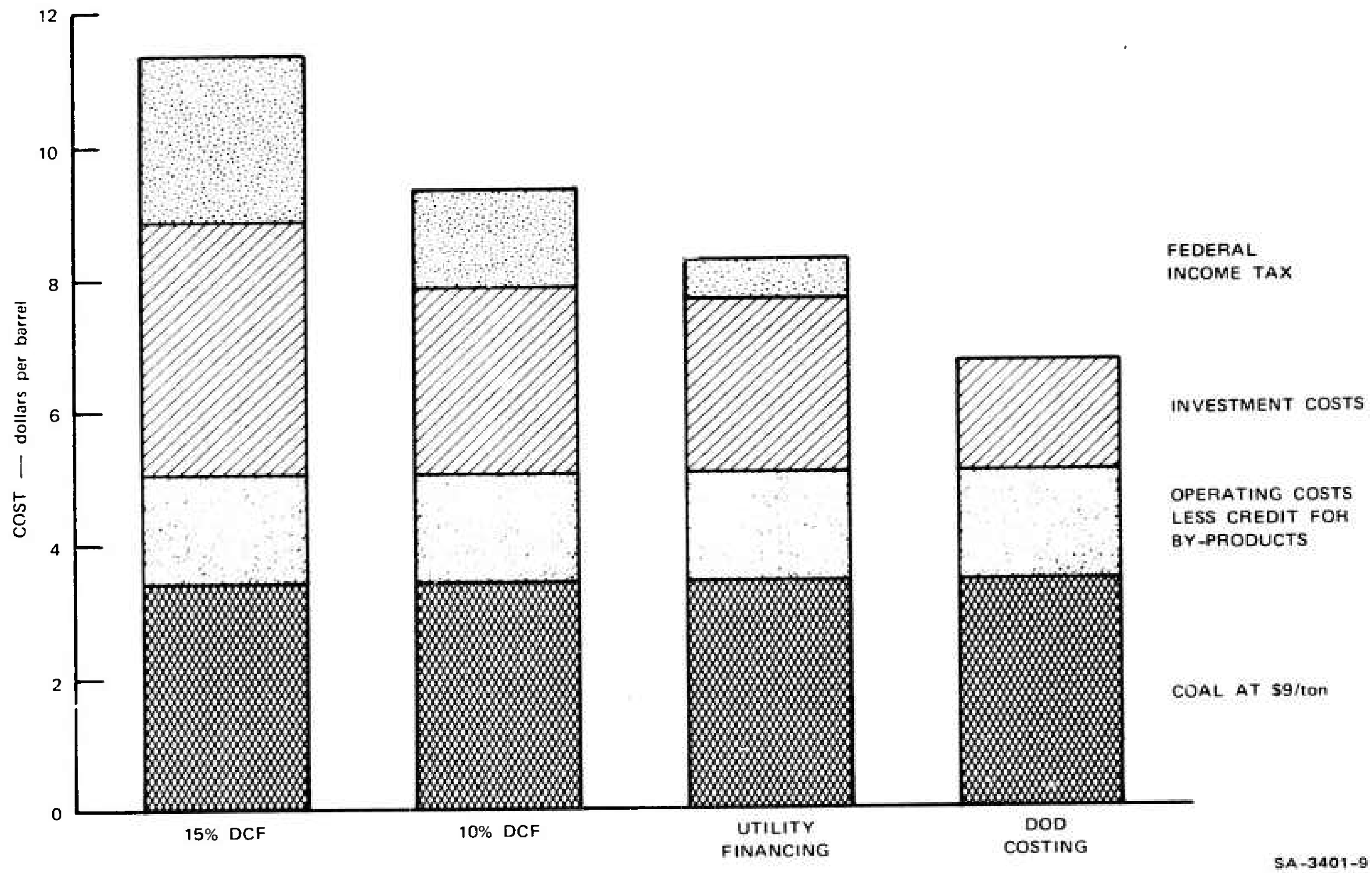

FIGURE 12 COST ELEMENTS OF SYNCRUDE FROM ILLINOIS NO. 6 COAL

were reduced. The lower DCF rate reduces the cost of syncrude by more than \$2 per barrel. Thus, a reduction in risk through some type of government action, such as a price guarantee, could significantly reduce the syncrude costs.

The federal income tax is a major element of cost, amounting to an average of \$2.51 per barrel with a 15 percent DCF. Although this tax would be a cost in the DoD budget in terms of the federal budget, it does not represent a true cost since the money is returned to the Treasury. In comparing the cost of syncrude with the cost of imported crude, the federal income tax component of the syncrude cost should be deducted. Excluding income tax, the estimated syncrude cost is less than \$9 per barrel with a 15 percent DCF, or less than \$8 per barrel with a 10 percent DCF. Federal income tax is also reflected in the coal price.

The industrial financing cases are based on a plant tax life of only 15 years, since the earliest syncrude plants might become obsolescent quite soon. A price guarantee might also increase the acceptable plant tax life, which would further reduce the syncrude cost.

Table 24 also gives the syncrude cost for a regulated utility type of financing.* The capital investment is raised from 65 percent debt at 10 percent interest and 35 percent equity at a 15 percent after-tax return, and the plant is assumed to be depreciated over 30 years. The total syncrude cost is then \$8.18 per barrel, which includes \$0.55 per barrel for federal income tax.

While it is not likely that DoD would own the syncrude plants, for comparison, the syncrude cost was also calculated as though the plant were a DoD facility. Using the standard DoD costing methodology, the

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*Using the procedure outlined in the report "The Supply-Technical Advisory Task Force--Synthetic Gas-Coal," National Gas Survey, Federal Power Commission, April 1973.

initial capital costs were converted to uniform annual costs, using a 6-1/8 percent discount rate and 25-year life applicable to DoD utilities. The syncrude cost is then $6.71 per barrel.

Table 25 and Figure 13 give the same information for costs of syncrude from Wyoming Powder River coal, with surface mined coal at $3 per ton. The difference in coal cost with the Wyoming coal, compared with that of the $9 per ton Illinois No. 6 coal, is $1.78 per barrel of syncrude. The total cost difference in the syncrude from the two coals, with a 10 percent DCF and excluding the income tax, is $1.49 per barrel. The lower cost of the Wyoming coal is partially offset by the lower heating value and hence lower syncrude yield per ton.

The effect of coal price on the cost of syncrude is shown in Figures 14 and 15. As previously discussed, the estimated cost of underground mined Illinois No. 6 coal is $9 per ton. At a likely upper limit of $15 per ton, the syncrude cost would be $11.80 per barrel, with a 10 percent DCF. However, Illinois has substantial strippable coal reserves, and if the surface mined coal were $5 per ton, the syncrude cost would be only $7.70 per barrel, with the same 10 percent DCF. For the Wyoming surface mined coal, $5 per ton is a likely upper limit, which gives a syncrude cost of $9 per barrel, with a 10 percent DCF.

The estimated syncrude cost, excluding the federal income tax, is substantially below the present delivered price of foreign crude of $12 a barrel. The development of substantial syncrude production may exert a downward pressure on foreign crude prices. Even if foreign crude prices were to drop below the costs of syncrude, the syncrude would not necessarily entail higher costs, since the correct comparison is with what foreign crude would have cost in the absence of a syncrude capability.

Table 25

TOTAL COSTS FOR H-COAL SYNCRUDE FROM WYOMING POWDER RIVER COAL
(Basis: 100,000 Barrels per Stream Day)

	Annual Costs (millions of dollars)		Cost per Barrel (dollars)
Coal cost at $3 per ton		$ 54.32	$1.65
Operating costs (excluding coal)		79.02	2.41
Credit for by-products			
Ammonia at $100 per ton	$10.47		
Sulfur at $25 per ton	1.54		
Total credit		(12.01)	(.37)
Net operating costs		$121.33	$3.69
Industrial--15 percent DCF			
Depreciation and net income (average)			3.66
Federal income tax (average)			2.42
Required syncrude revenue		321	$9.77
Industrial--10 percent DCF			
Depreciation and net income (average)			2.67
Federal income tax (average)			1.43
Required syncrude revenue		256	$7.79
Utility financing			
Depreciation and net income (average)			2.52
Federal income tax (average)			53
Required syncrude revenue		202	$6.74
DoD costing			
Investment cost			$1.61
Required syncrude revenue		174	$5.30

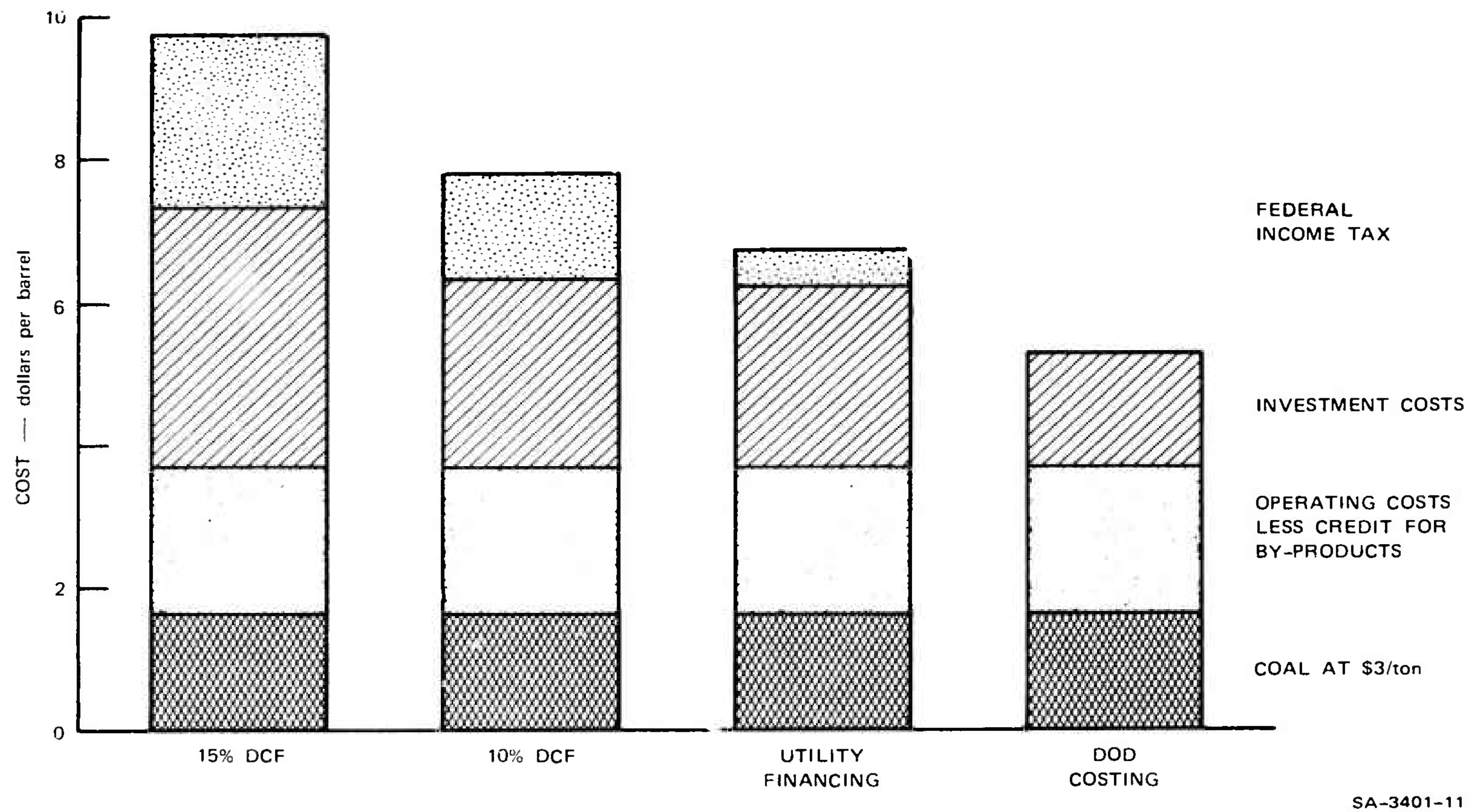

FIGURE 13 COST ELEMENTS OF SYNCRUDE FROM WYOMING POWDER RIVER COAL

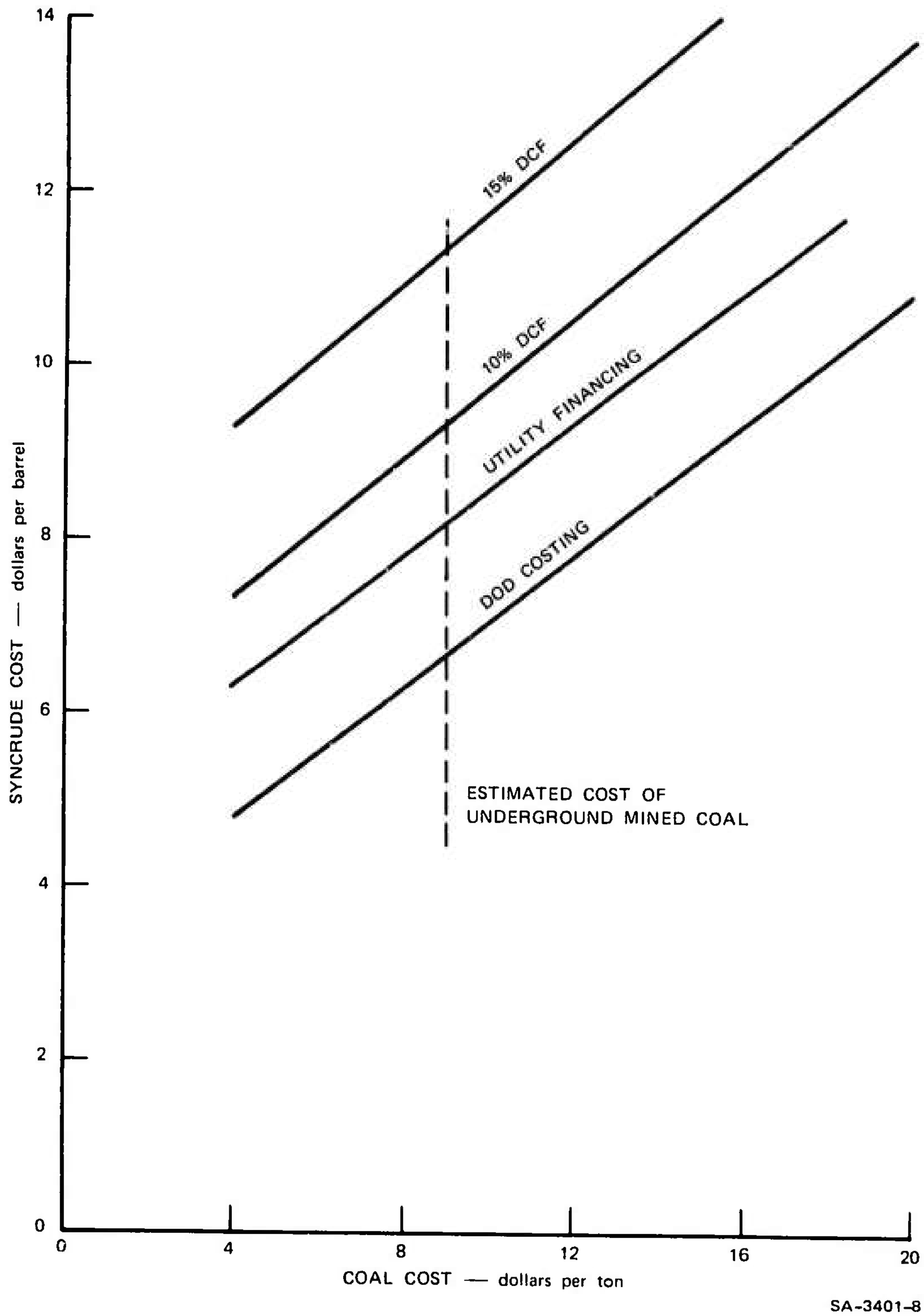

FIGURE 14 COST OF SYNCRUDE FROM ILLINOIS NO. 6 COAL

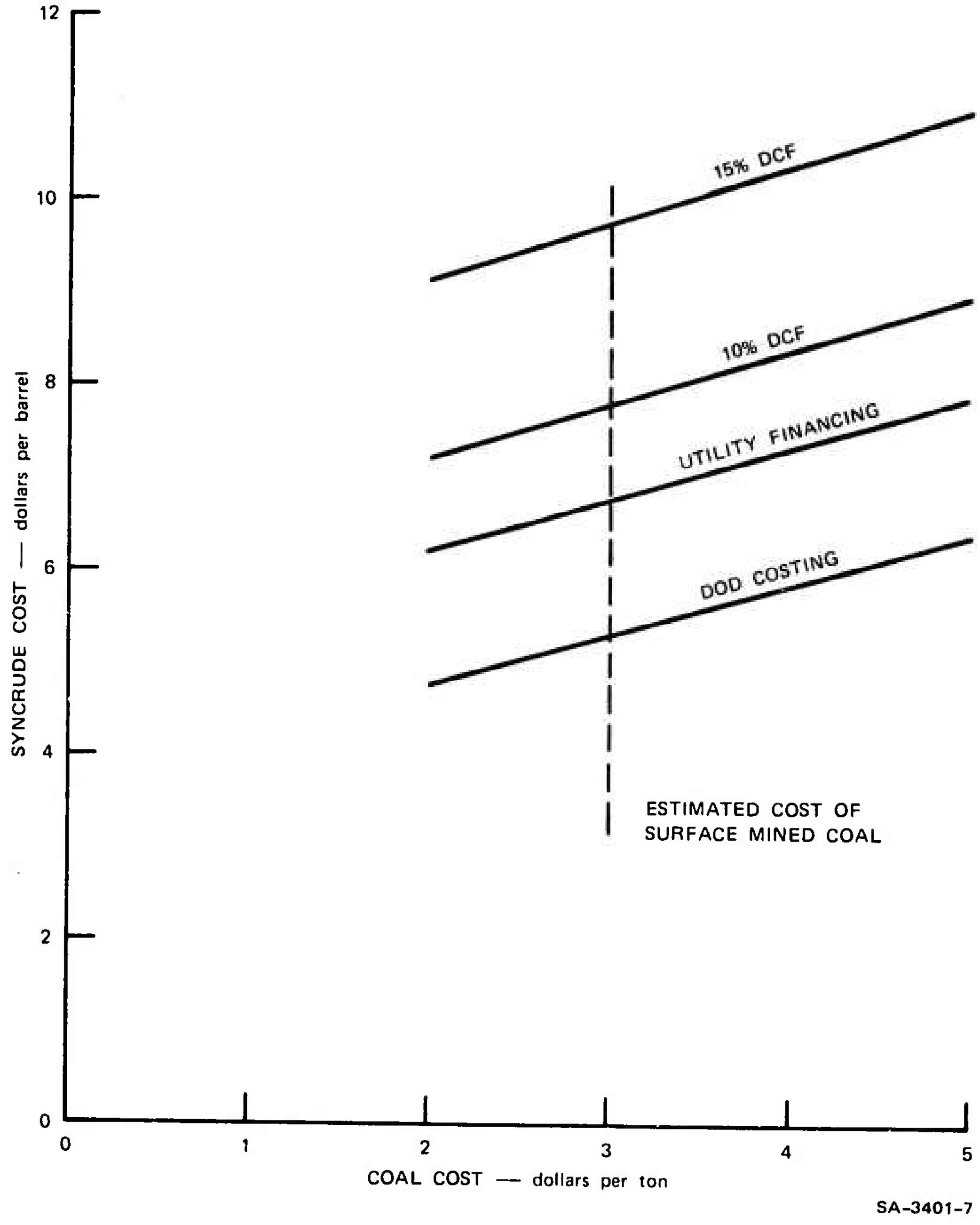

FIGURE 15 COST OF SYNCRUDE FROM WYOMING POWDER RIVER COAL

Total Cost of Syncrude Refining

The estimated capital investment and operating costs, excluding feedstock, for H-coal syncrude refining are given in Section V. This discussion develops the total syncrude refining costs for the different cases to include feedstock and financing costs.

Table 26 gives the annual costs and costs per barrel of products for refining syncrude in new refineries, assuming a syncrude price of $10 per barrel.

The net operating cost is the sum of the syncrude cost and the other operating costs, less credit for the sale of by-products. The apparent discrepancy in the table of syncrude cost per barrel of product from the assumed $10 per barrel arises because in one case the volume of products is slightly less than the volume of the syncrude and in the other case, greater than the volume of the syncrude. The investment cost includes depreciation, net income, and federal income taxes. The investment cost is for an industrial type of financing with either a 10 or 15 percent DCF rate of return on investment. The syncrude cost is the major element in the cost of the products.

The effect of syncrude price on the cost of the products is shown in Figure 16. The change in product cost versus change in syncrude price (in dollars per barrel) is greater than one to one because the syncrude price is also reflected in the working capital and hence in the financing cost as well as the operating costs.

Table 27 gives the annual costs and the costs per barrel of products for a typical modern refinery processing crude only, and for a modification of that refinery to process 50 percent syncrude and 50 percent crude, with a 15 percent DCF rate of return. The syncrude processing increases the refining cost by $0.28 per barrel of product. In terms of portion of

Table 26

TOTAL COSTS OF REFINING SYNCRUDE IN NEW REFINERIES
(Basis: 100,000 Barrels per Stream Day)

	Annual Costs (millions of dollars)		Cost per Barrel (dollars)	
	Minimum Cost Refinery	Maximum Jet Fuel Refinery	Minimum Cost Refinery	Maximum Jet Fuel Refinery
Syncrude cost at $10/barrel	$333.35	$333.35	$10.05	$ 9.51
Operating cost (excluding syncrude)	23.52	46.04	0.70	1.31
Credit for by-products	(0.13)	(0.25)	--	(0.01)
Net operating cost	$356.74	$379.14	$10.75	$10.81
Investment cost*				
15% DCF	63.83	83.83	1.93	2.39
10% DCF	44.62	57.83	1.35	1.65
Required product revenue				
15% DCF	420.57	462.97	12.68	13.20
10% DCF	401.36	436.97	12.10	12.46

*Depreciation, net income, and federal income tax.

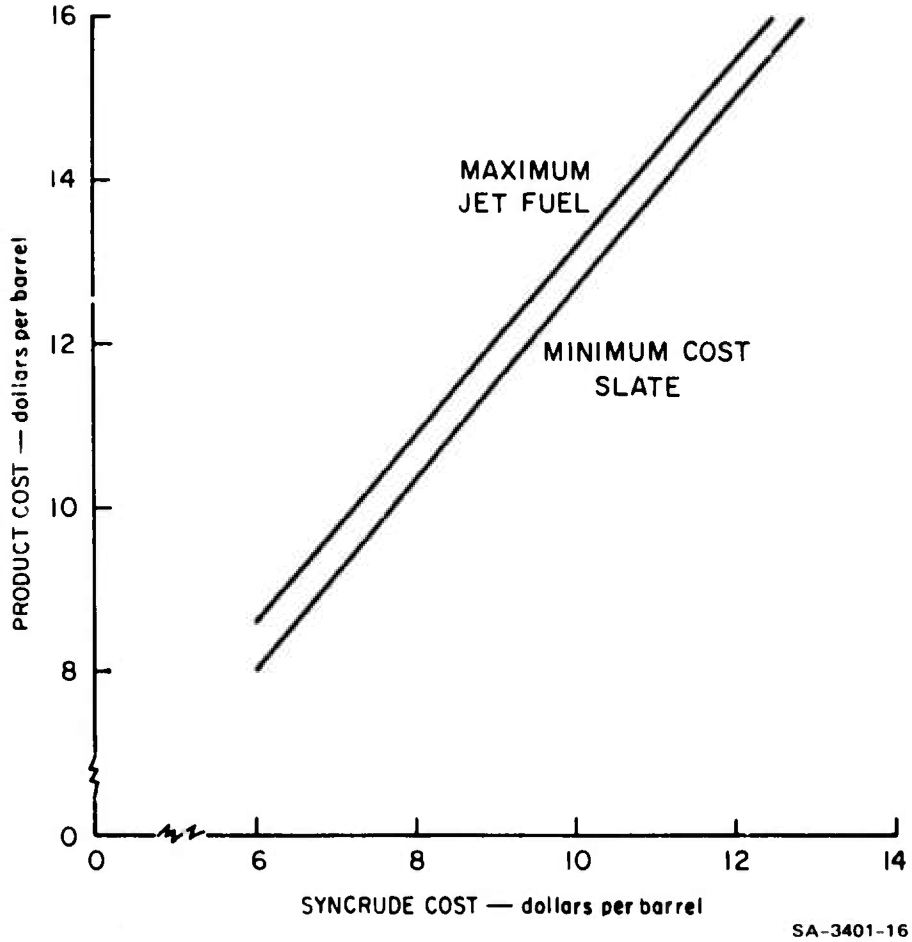

FIGURE 16 COST OF PRODUCTS VERSUS SYNCRUDE PRICE (NEW REFINERY, ALL SYNCRUDE INPUT, 15 PERCENT DCF)

Table 27

TOTAL COSTS OF REFINING CRUDE AND SYNCRUDE IN MODIFIED REFINERY
(Basis: 170,000 Barrels per Stream Day)

	Annual Costs (millions of dollars)		Cost per Barrel (dollars)	
	Existing Refinery, Crude Only	Modified Refinery, 50% Crude, 50% Syncrude	Existing Refinery, Crude Only	Modified Refinery, 50% Crude, 50% Syncrude
Feedstock at $10/barrel	$566.66	$566.66	$ 9.61	$ 9.48
Operating cost (excluding feedstock)	76.60	87.03	1.30	1.46
Credit for by-products				
Coke	4.93	2.47	(0.08)	(0.04)
Sulfur	3.56	1.95	(0.06)	(0.03)
Total credit	$ (8.50)	$ (4.42)	$(0.14)	$(0.07)
Net operating cost	634.76	649.27	10.76	10.87
Investment cost* (15% DCF)	132.18	143.61	2.24	2.40
Required product revenue (15% DCF)	766.94	792.88	13.01	13.27

*Depreciation, net income, and federal income tax.

the product output attributable to the syncrude input, the refining cost is $0.52 per barrel higher than the refining cost for crude, or a little over $0.01 per gallon.

The comparable product cost for refining syncrude in a new minimum cost refinery (Table 26) is $12.68 per barrel. This product cost is lower than the product costs for refining crude or crude plus syncrude in an existing or modified refinery because of the costs of conversion to produce gasoline as the major part of the yield in the existing refinery. Since the basis of the new refinery was 100,000 barrels per stream day, and that of the existing refinery 170,000 barrels per stream day, with the attendant economies of scale, the actual disparity in costs is somewhat greater than indicated.

The product costs of $13.20 per barrel for the new syncrude refinery designed to maximize jet fuel yield are more comparable with the product costs for the existing refinery.

VIII TRANSPORTATION

Three syncrude plants, each of 100,000 barrel-per-day capacity, could provide most of the DoD petroleum products consumed within the coterminus United States. However, the distribution from three plant locations to bases spread over the United States would entail substantial transportation costs. A preferable alternative might be to trade the syncrude or syncrude products for products in the local area of the DoD installations. To indicate the cost penalty that direct DoD use of the products from a limited number of syncrude plants would incur, a brief analysis is made of the transportation costs.

Transportation of Coal

If the coal conversion plant is located adjacent to the mine, the coal is moved by belt conveyors directly to the conversion plant. A smaller amount of additional coal is conveyed to a storage area for operating the plant on weekends and during mine shutdown periods.

If it is necessary to transport the coal appreciable distances, the coal is moved by truck from the mine to a tipple where it is crushed and loaded on unit trains. Since modern tipples are designed with loading rates of 1,500 to 3,000 tons per hour, an entire 100-car unit train can be loaded in four hours or less. Cost of tippling ranges from $0.20 to $0.40 per ton of coal handled.

The cost of transporting coal by unit train depends on shipping distance, car and train size, coal density, terrain, train speed, and loading-unloading turnaround times. Figure 17 indicates coal transportation costs for unit coal trains (100 ton cars, 100 cars per train, 40 miles per hour

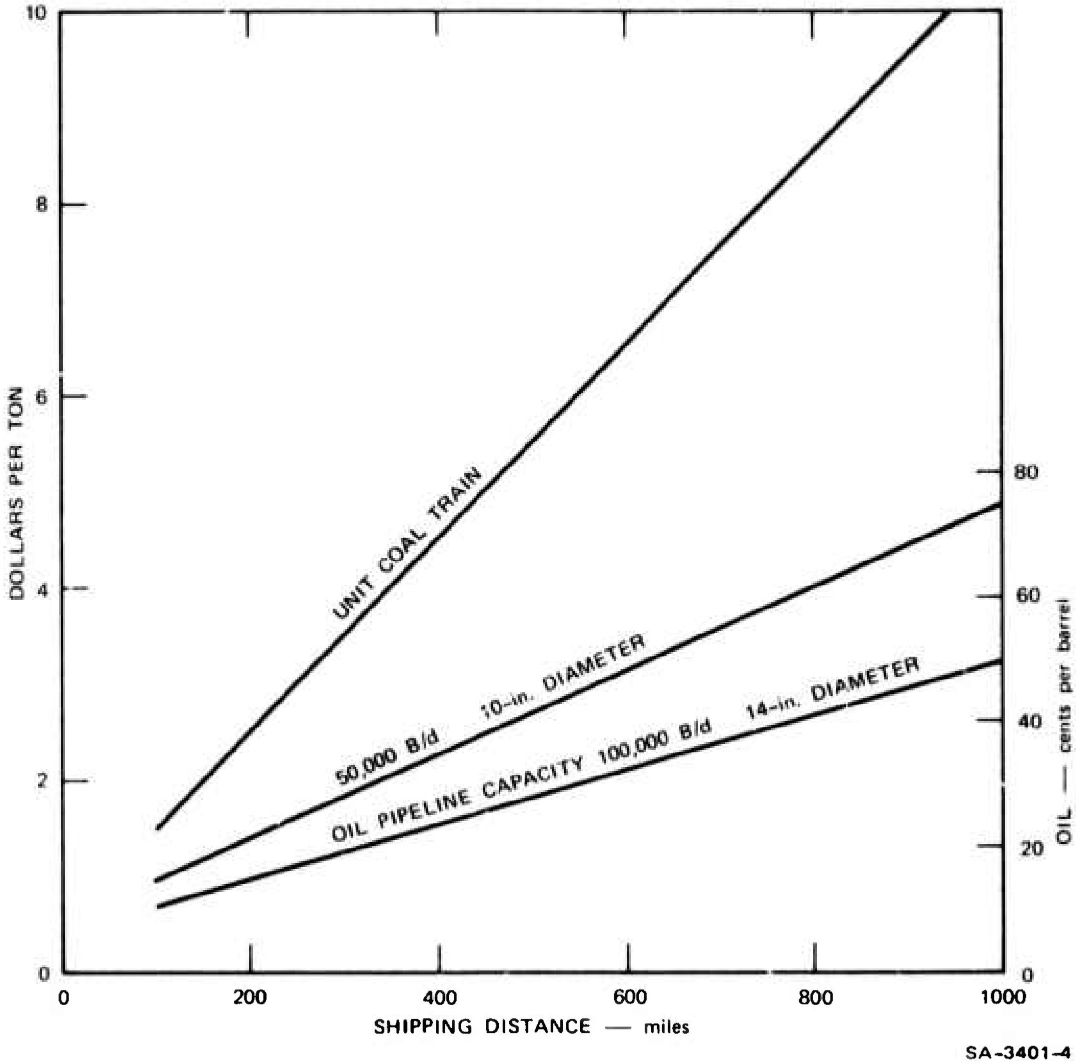

FIGURE 17 COAL AND SYNCRUDE TRANSPORTATION COSTS

average speed) for transporting western coal to the Midwest. Based on a tipple cost of \$0.30 per ton and a shipping rate of 11 mills per ton mile, it would cost \$12.40 per ton to move the as-mined Wyoming coal 1,100 miles to an Illinois conversion plant. Adding the \$3 per ton mining cost to the shipping charges gives a cost of \$15.40 per ton for Wyoming coal delivered to Illinois, which, since it is higher than the cost of eastern coal, makes this option appear uneconomic. However, this alternative may be

necessary in the event that sufficient water is not available in the West to support a significant coal conversion industry and the coal must be moved to areas where water is available. At present, there is a shortage of coal cars in the United States and some western railroads are operating at near capacity. A 100,000 barrel-per-day coal conversion plant in the eastern United States operating on western coal would require shipping 55,000 tons per day, or 18 million tons per year. In the Wyoming to Illinois case, five 100-car unit trains would be required each day, and with a three-day round trip, a total of 15 trains (1.500 cars) would be required. This approach to coal liquefaction in the East would undoubtedly necessitate installation of additional trackage and purchase of considerable rolling stock.

In areas with navigable rivers or lakes, coal can be transported by barge at lower cost than by train. Transportation charges for moving coal in large barges average 4 mills per ton-mile.

Transportation of coal by slurry pipeline is a recent development that is receiving considerable attention. Finely ground coal is slurried with water and pumped through pipelines much as oil is pipelined. To date, applications of this coal transporting method have been limited to a few medium length lines in difficult terrain that would result in high track construction cost. Application of coal pipelining in the West may be limited by a lack of available water unless water is imported from other areas or recycled.

Pipelining Oil

The cost of pipelining crude oil and refined products depends on shipping distance, volume pumped, type and number of products handled, and terrain to be crossed. Pipelines are sized by determining the optimal economic minimum of capital and operating costs. Important capital

cost items are right-of-way, pipes and installation, and pumping stations; maintenance and power are important operating costs. Pipelines are frequently installed initially with 100 to 200 miles between pumping stations and the pipeline capacity later increased by adding more pumping stations. Station spacing may be reduced to 20 to 30 miles to overcome the pressure drop between stations at higher flow rates. Power consumed in oil pipelining is significant, and some 45,000 HP is required to move 100,000 barrels per day of syncrude over a 1,100 mile distance.

The costs of pipelining oil are indicated in Figure 17 for pipelines with capacities of 50,000 to 100,000 barrels per day and distances of 100 to 1,000 miles. Pipelining multiple products through a single pipeline is more difficult than pipelining crude, and the resulting costs are higher. Since the products must be pumped sequentially, operating costs are higher and larger storage capacities are required at both the point of origin and receiving end. Products are batch-sequenced by quality.

Product inventory in the pipeline is appreciable. For example, a 20-inch diameter, 1,100 mile pipeline, transporting 200,000 barrels per day will contain 2.3 million barrels or about 10 days' pumping rate. Minimum acceptable batch size is usually about 20 percent of a day's capacity and maximum batch size of up to 3 days' capacity. Thus, a long pipeline could contain at one time from 10 to 20 products that require careful scheduling of loading and unloading operations and additional storage facilities on each end of the pipeline. Since the products are usually not positively separated, there is some mixing at product interface, which may require reprocessing the overlap portion when the product has rigid specifications, particularly on the portion of the cycle where high quality products follow lower grade products

The cost of pipelining products is 25 percent higher than that for pipelining syncrude.

Distribution to DoD Installations

The location considerations for syncrude plants in Wyoming and Illinois were discussed in Section VI. As an example, it is assumed that one syncrude plant would be located in Wyoming, with the syncrude sent by pipeline 600 miles to refineries in eastern Kansas; two syncrude plants would be located in Illinois, with refining also in the same area.

Taking account of the DoD petroleum product consumption in each of the ten FEA regions, the average transportation distance might be 565 miles by pipeline, plus further distribution within the regions by train, an additional distance of 200 miles. Since product pipelines in the desired flow directions to some areas do not now exist, an alternative of transportation by train only would entail an average distance of 740 miles.

Using Figure 17 for pipeline transportation costs, the costs of the trip segments in dollars per barrel are as follows:

Syncrude from Wyoming to eastern Kansas, 600 miles by 14-inch line	\$0.32
Products by pipeline, 565 miles by 10-inch line	0.59
Products by train, 200 miles at 2¢ per ton mile	0.56
Products by train, 740 miles at 2¢ per ton mile	2.08

Since only one-third of the syncrude is transported to refineries in a different area, the average cost is \$0.11 per barrel. The total average transportation cost (dollars per barrel) for the two alternatives for syncrude product transportation is then as follows:

Pipeline plus train	\$1.26
Train only	2.19

Thus, depending on the extent to which pipelines could be used for distribution to the DoD installations, the transportation cost might range from $1.26 to $2.19 per barrel. Barge transportation costs are between the pipeline and train costs. This cost penalty for direct DoD use of the syncrude products is not so great as to completely rule it out if complete DoD fuel independence is considered sufficiently important, but it is substantial enough to make trading for local products appear preferable. Locally purchased products also include a transportation cost element, but the distances would be shorter, and, since shipments are mostly by pipeline and in larger quantities, the unit transportation costs would be lower than for direct distribution from DoD dedicated plants.

IX DEVELOPMENT SCHEDULES

Syncrude Development

Considerable process development is required before construction of commercial-sized coal liquefaction plants is possible. Because of the technical uncertainties and cost involved, coal conversion process development is usually accomplished in a series of scale-ups requiring progressively larger equipment. The technical and economic feasibility of the process is continually evaluated during scale-ups, and the project is terminated if it appears unattractive.

The conceptual process is first tested in bench scale equipment having a coal feed rate of 10 to 20 pounds per hour, followed by construction of a process development unit that can process 100 to 200 pounds per hour. A pilot plant is constructed next with a feed rate of 10 to 100 tons per day, followed by a 500 to 2,000 ton-per-day semicommercial plant; finally, the full sized commercial plant is built. Thus, four stages of progressively larger development are needed to bring a process from the conceptual stage to a commercial plant capable of handling 10,000 to 40,000 tons of coal per day.

More development time is required to complete each stage in a coal liquefaction process development than traditionally needed to develop chemical or refining processes. The physical nature of coal and resulting mixture of solids, gas, and liquids greatly complicate processing and have slowed progress on process development. Based on progress to date, the following approximate times (in years) are required to complete the various stages of coal liquefaction process development.

	Plant Construction	Plant Evaluation or Start-up
Bench scale	0.4	1.0
Process development unit	0.8	1.8
Pilot plant	1.4	2.0
Semicommercial plant	2.0	0.8
Commercial plant	4.0	0.4

Based on the above schedule and assuming no time overlaps, 14 years would be required from process conception to a commercial plant. By overlapping the separate schedules, the total development time could probably be reduced to ten years.

At present, most coal liquefaction processes have completed bench scale, while a few have progressed through the development unit stage and are now in the pilot plant stage. A 3 ton-per-day pilot plant for the H-coal process has been operated. Therefore, it appears that a full scale coal liquefaction plant could come on stream in the United States in six to eight years, or in 1980 to 1982.

Schedule for Syncrude Refinery

The time required to bring a syncrude refinery onstream is primarily determined by the time required for site acquisition and approval plus plant construction. In areas where resistance by environmental interest groups is high, such as currently experienced in the New England and mid-Atlantic areas, several proposed new refinery projects have been blocked indefinitely. Other areas of the country have experienced less difficulty in this respect, especially where other refineries and petrochemical plants exist.

The construction of a new refinery at a new site typically has required two to three years from groundbreaking to start-up, as indicated

in the following tabulation. However, these projects were constructed during a period when few other projects were competing for construction industry resources.

Company	Location	Capacity MB/SD	Construction Period
Shaheen Natural Resources	Newfoundland	100	Fall 1970-Fall 1973
Amoco, Ltd.	Milford Haven, United Kingdom	80	Spring 1971-Fall 1973
Gulf Oil	Alliance, Louisiana	160	Dec. 1969-Jan. 1972
Mobil Oil	Joliet, Illinois	164	Fall 1970-Jan. 1973

Recently, capacity shortages have brought forth a wave of new construction projects in the refining, petrochemical, and utility industries. As a result, the lead time for major equipment items, such as thick walled pressure vessels, has surpassed two years, and construction contractors have backlogs of cost-plus contracts. The impact of these factors is certain to extend construction times beyond the two to three years previously experienced, and when combined with the increasingly complex and stringent pollution control constrains, these lead times could easily stretch the time required to implement a new refinery to the range of five to seven years.

X CONSTRAINTS

A number of factors have the potential for constraining the growth of coal liquefaction. These include limitations on water supplies, the availability of capital, the availability of manpower for coal mining and construction, environmental impacts, and regulatory restrictions. The DoD petroleum product consumption within CONUS could nearly be met from three syncrude plants of 100,000 barrels per day capacity. Of itself, a development of that magnitude would pose little problem. However, an enormous expansion of the energy industries will be required to meet the objective of energy independence. The development for DoD purposes will be competing within this overall energy industry expansion. Some of these constraints are discussed below.

Water Availability

Any plan for converting coal to liquid fuels must carefully assess the availability of water resources in the coal producing areas, since coal conversion processes consume appreciable amounts of water, both in the process and for cooling purposes. Water availability is not expected to be a problem in the development of eastern coal deposits roughly east of the Mississippi River. In the western United States, it is expected that insufficient supply of water will severely limit future development of a large scale coal conversion industry.

A coal liquefaction plant consumes about 6.8 barrels of water to produce one barrel of syncrude. In a 100,000 barrel-per-day plant, this is equivalent to 20,000 gpm, or 28,000 acre-feet per year.

Western states with coal resources are generally arid, averaging one to 20 inches of precipitation a year. Much of the runoff water has been committed to agriculture or allocated to other downstream states, which limits the availability of water for a new industry. Availability of water resources in the West depends on a set of complex state water rights and regulations and on demands by different consuming groups.

Table 28 indicates the estimated present water availability for new industrial development in the western coal states based on a recent report by the Department of the Interior. It can be seen from the figures in Table 28 that a coal liquefaction plant that requires 28,000 acre-feet

Table 28

PRESENT WATER AVAILABILITY
FOR INDUSTRIAL DEVELOPMENT
IN WESTERN STATES*[17]

State	Thousands of Acre-Feet per Year
Arizona	57.5
Colorado	291
Montana	550[18]
New Mexico	84-99
North Dakota	330[18]
Utah	132-250
Wyoming	120

[17]Southwest Energy Study, Department of the Interior (1972).

[18]North Central Power Study, Department of the Interior (1971).

per year of water would consume an appreciable fraction of the available water supply in some states. The National Academy of Sciences* recently concluded that "enough water is available for mining and rehabilitation at most sites, (but) not enough water exists for large scale conversion of coal to other energy forms" and recommended "that alternate locations be considered for energy conversion facilities."

Water consumption can be reduced 50 percent or more by using air coolers in place of wet cooling towers and reusing waste water, as will be done in the El Paso coal gasification plant. However, these changes do increase the investment and slightly reduce thermal efficiency. Other plans that are being studied to alleviate the western water shortage entail importing water from areas with excess supplies. This approach would require massive investment and energy requirements.

In addition to the problem of water availability is that of treatment and disposal of waste water from coal conversion processes. The waste water will contain toxic materials such as phenols and cyanides that must be removed. In some areas, it may be necessary to remove nontoxic salts to limit stream pollution. Undoubtedly, strict pollution controls will be placed on both air emissions and water effluents from coal conversion plants in both eastern and western locations.

Economic Constraints on Growth Rate of Coal Liquefaction

Coal liquefaction processes are capital intensive projects and will require large amounts of debt or equity capital. Each 100,000 barrels per day of incremental added capacity of coal liquids will require an investment of $600 million for the conversion plant, plus an additional $250 million for the coal mines.

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[16]"Rehabilitation Potential of Western Coal Lands," National Academy of Sciences (1974).

About half of the DOD requirements could be met with 300,000 barrel-per-day capacity, or an investment of $2.5 billion for three conversion plants and mines. On the other hand, replacing a significant portion of U.S. dependence on foreign oil would require a very large investment. The United States currently imports 3.2 million barrels per day of crude and 2.7 barrels per day of oil products. Reducing the present U.S. dependence on foreign imported crude and oil products by 50 percent would require construction of 30 coal liquefaction plants producing 100,000 barrels per day and an investment of $25 billion for plants and mines.

Although this capital requirement of $25 billion (say $2.5 billion per year over a 10-year period) of itself would not impose strain on capital resources, the syncrude developments would be competing with the enormous capital requirements of the overall energy industries. The National Academy of Engineering (NAE)[11] estimated the total capital requirements of the energy industries (oil, gas, uranium, coal, coal synthetic fuels, oil shale, electric power, and supporting infrastructure) through 1985 to be $700 billion, or approximately $60 billion per year. For a perspective, this rate can be compared with the total investment in industrial plant and equipment in 1970 of about $100 billion. However, the NAE concluded that, with adequate revenues, the energy industries should be able to attract the necessary capital resources.

Construction of the initial first generation plants will entail appreciable technical and marketing risks that will require an adequate return to both the equity and debt investor. It is expected that interest on debt will have to be between 10 and 12 percent and return on equity 14 and 16 percent to attract the necessary risk capital. The resulting

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[11]"U.S. Energy Prospects: An Engineering Viewpoint," National Academy of Engineering (1974).

high capital connected costs would total half the syncrude cost in a 100 percent equity case and would result in syncrude prices that are vulnerable to natural crude availability. It may be necessary to establish economic incentives to attract capital for a coal liquefaction industry. These incentives might include:

- Guaranteed floor prices for products.
- Investment tax credits or rapid plant depreciation.
- An increased depletion allowance for coal above the present 10 percent, or a decreased depletion allowance on oil below 22 percent.
- Low interest government loans similar to World Bank or Export-Import Bank.
- Tax-free commercial bonds such as are now issued for pollution abatement.
- Direct subsidy to synthetic fuels industry.
- Import tax on foreign crude to maintain its price at or above the cost of syncrude.

Constraints on Coal Liquefaction Plant Construction

Construction of a coal liquefaction industry depends on a number of interrelated factors, including technical development, economics, labor, and supply of materials. As indicated previously, only one commercial coal liquefaction plant is now operating in the world--the SASOL Fischer-Tropsch plant in South Africa. While considerable progress has been made on developing new and improved coal liquefaction processes, the effort to date has used largely small scale equipment and has been conducted on unintegrated portions of processes. Appreciable technical problems have been encountered that will require solution before commercial plants can be constructed. These problems include:

- Separation of ash and unreacted coal from the heavy crude oil.

- Development of methods for feeding coal into vessels at high pressure and temperature.
- Extension of catalyst life and catalyst regeneration.
- Recovery and disposal of by-products and disposal of toxic waste materials.
- Development of methods for upgrading and refining coal syncrude to specification products.

The present government and industry development efforts are directed toward solving the above problems, with a high probability of success. Therefore, the process development or technology constraint is primarily the time required to develop the information necessary to design a full scale commercial plant.

Construction of coal liquefaction plants will require significant amounts of construction materials and skilled labor. Factors that could limit the rate of construction of coal liquefaction plants include:

- Availability of skilled labor to design and construct plants. A 100,000 barrel-per-day syncrude plant will require an estimated 5,000 man-years of skilled construction labor.
- Licensing availability and royalty payments for proprietary processes.
- The supply of high alloy steels, catalysts, and high-temperature refractories.
- The time requirement for design and construction of a coal liquefaction plant and the construction capability of knowledgeable engineering firms.
- Limits on manufacturing capacity for specialized equipment such as compressors, high pressure vessels, coal mining and handling equipment, and gas purification equipment. For example, there is a 5-year backlog on draglines used in surface coal mines, largely because of the limited number of manufacturers. The following tabulation indicates current lead times (in years) for other items of coal liquefaction equipment.

High pressure vessels	4
Gas compressors	2.3
Large heat exchangers	1.5
High alloy piping and valves	1.4
High pressure pumps	1.2

Manpower

Coal Mining

The amount of coal and number of coal miners required to supply the coal for three syncrude plants are tabulated below. Each plant has capacity for 100,000 barrels per day for DoD use; or 30 plants of that size could be used to supply half of current crude and product imports, either for underground mined Illinois No. 6 coal or for surface mined Wyoming Powder River coal. The numbers are based on 20 tons per man-day for underground mining and 100 tons per man-day for surface mining.

	Miners		Coal (millions of tons per year)	
	3 plants	30 plants	3 plants	30 plants
Illinois No. 6 coal, underground mined	8,190	81,900	38	377
Wyoming Powder River coal, surface mined	2,365	23,650	54	544

For comparison, coal production is now about 600 million tons per year, and the number of coal miners is 125,000. Thus, the 30-plant case would require a large expansion in coal production, even without regard to the increase in coal consumption for gasification and electric power.

Construction Workers

As previously mentioned, a 100,000 barrel-per-day syncrude plant will require an estimated 5,000 man-years of skilled construction labor.

For construction of 30 plants over a 10-year period, 15,000 construction workers would be required. The NAE[11] estimated that the construction workers required in the industrial construction areas would increase from 149,000 in 1973 to 341,000 in 1985. Total building trades membership in 1973 was 2.1 million.

Plant Operators

The number of syncrude plant operators required is 450 for a 100,000 barrel-per-day plant. Since syncrude production is not labor intensive, there should be little problem in obtaining enough manpower.

Engineers

The NAE estimated that the engineering manpower required for the energy industries, including both the operating industries and the engineering-construction industry, would increase 40 percent, from 74,400 in 1973 to 104,700 by 1980. Qualified engineers are in short supply now, and enrollment in engineering schools is not keeping up with industry requirements. Engineers employed by the energy industries constitute less than 10 percent of total U.S. engineering employment. Transfers from other fields and special training will be required to provide enough engineering for the expansion of the energy industries.

Regulatory Constraints

In recent years, concern for environmental quality and use of natural resources has conflicted with many new energy development plans. This conflict of interest has occurred in both urban and rural areas and

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[11] "U.S. Energy Prospects: An Engineering Viewpoint," National Academy of Engineering, 1974

undoubtedly will slow future development of a synthetic fuels industry. Public and legislative concern for the consequences of coal utilization has increased considerably in the last five years and promises to continue. Recent experience in proposed southwestern coal gasification plants indicates that numerous governmental agencies must be satisfied before plant construction can start. The obstacles to be overcome in terms of these interests include:

- Obtaining water rights from federal, state, or local governmental agencies.
- Gaining approval for the environmental impact statements, which must include acceptable plans for coal mining and control of all plant wastes, including air emissions, water effluents, solid waste, and noise.
- Obtaining plant construction permits that satisfy all concerned governmental and citizen groups.
- Satisfying government pricing policies.
- Meeting all regulations for the health and safety of workers.
- Getting a federal lease for mining coal on western public lands.

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